

Guideline for Greenhouse Gas Emissions Reporting

(as set out under Ontario Regulation 452/09 under the Environmental Protection Act)

Ontario Ministry of the Environment

December 2009

[This version of the Guideline dated December 2009 (PIBS# 7308e) has been superseded by the version of the Guideline dated December 2010 (PIBS# 8024e)]

This Guideline is made in English only

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1. Introduction

Ontario's Greenhouse Gas (GHG) Emissions Reporting Regulation (Ontario Regulation 452/09) requires in Section 4(1) the use of standard quantification methods for each of the specified sources. These methods are set out in Section 4 of this Guideline.

The majority of the methods are based on the Essential Requirements for Mandatory Reporting published by the Western Climate Initiative (WCI) on July 15, 2009. The remaining methods adopt by reference methods set out in the mandatory Reporting of Greenhouse Gases rule finalized by the United States Environmental Protection Agency (U.S. EPA) on September 22, 2009. Some of the methods provide two or more options for calculation, sampling, analysis and measurement procedures depending on the type of fuels and other material used in the manufacturing process.

Section 4(5)(a) of the Regulation also provides for the use of best alternative quantification methods for reports submitted in 2011 on 2010 GHG emissions. Section 3 of this Guideline sets out these best alternative quantification methods.

Section 5 of this Guideline provides a listing of the technical reference documents referred to within the methods.

2. Definitions

"Associated gas" means a natural gas which is found in association with crude oil, either dissolved in crude oil or as a cap of free gas above the crude oil.

"Barrel" or "bbl" means a volume equal to 42 U.S. gallons.

"Bottoming cycle plant" means a cogeneration plant in which the energy input to the system is first applied to a useful thermal energy application or process, and at least some of the reject heat emerging from the application or process is then used for electricity production.

"Calcination" means the thermal decomposition of carbonate-based minerals, into one or more oxides and carbon dioxide

"Calcine" means to heat a substance to a high temperature but below its melting or fusion point causing oxidation or reduction.

"Calcined byproduct/waste type" refers to lime kiln dust and other partially calcined materials and co-products generated during the production of quicklime.

"CAS number" stands for Chemical Abstracts Service Registry number assigned to the contaminant.

"Catalytic cracking" means the process of breaking down larger, heavier, and more complex hydrocarbon molecules into simpler and lighter molecules through the use of a catalyst.

“Catalytic reforming” means the process of using controlled heat and pressure with catalysts to rearrange certain hydrocarbon molecules.

“Cement kiln dust” or “CKD” means the fine-grained, solid, highly alkaline waste removed from cement kiln exhaust gas by air pollution control devices, consisting of partly calcined kiln feed material, dust from cement kilns and bypass systems, including bottom ash and bypass dust.

“Clinker” means the mass of fused material produced in a cement kiln from which finished cement is manufactured by milling and grinding.

“Cogeneration unit” means a stationary fuel combustion device which simultaneously generates electrical and thermal energy that is (i) used by the person where the cogeneration unit is located; or (ii) transferred to another facility for use by that facility.

“Cogeneration system” means individual cogeneration components including the prime mover (heat engine), generator, heat recovery, and electrical interconnection, configured into an integrated system that provides sequential generation of multiple forms of useful energy (usually electrical and thermal), at least one form of which the facility consumes on-site or makes available to other users for an end-use other than electricity generation.

“Coke ” means a solid residue consisting mainly of carbon which is derived either from the cracking of petroleum hydrocarbons in a refinery coker unit (petroleum coke) or from the destructive distillation of low-ash, low-sulfur bituminous coal (coal coke).

“Coke burn-off” means the removal of coke from the surface of a catalyst through combustion during catalyst regeneration.

“Combustion emissions” means greenhouse gas emissions occurring during the exothermic reaction of a fuel with oxygen.

“Continuous emissions monitoring system (CEMS)” means the total equipment required to obtain a continuous measurement of a gas concentration or emission rate from combustion or industrial processes.

“Electricity generating unit” or “EGU” means any combination of physically connected generator(s), reactor(s), boiler(s), combustion turbine(s), or other prime mover(s) operated together to produce electricity.

“Emission factors” - means the rate at which a pollutant is released into the atmosphere (or captured) as a result of some process activity or unit throughput. The EFs used may be average or general EFs, or technology-specific EFs.

“Engineering estimates” - means estimating emissions from engineering principles and judgment, using knowledge of the chemical and physical processes involved, the design features of the source, and an understanding of the applicable physical and chemical laws.

“Equipment leak” means releases of fugitive greenhouse gas emissions from equipment including valves, pump seals, flanges, compressors, sampling connections, and open-ended lines and excluding storage tank emissions.

“Flexigas” means a low heat content gaseous fuel produced through the gasification of coke.

“Fluid catalytic cracking unit” or “FCCU” means a process unit in a refinery in which crude oil or a crude oil-derived feedstock is charged and fractured into smaller molecules in the presence of a catalyst, or reacts with a contact material to improve feedstock quality for additional processing, and in which the catalyst or contact material is regenerated by burning off coke and other deposits. The unit includes, but is not limited to, the riser, reactor, regenerator, air blowers, spent catalyst, and all equipment for controlling air pollutant emissions and recovering heat.

“Fluid coking” means a thermal cracking process utilizing the fluidized-solids technique to remove carbon (coke) for continuous conversion of heavy, low-grade oils into lighter products.

“Fuel analytical data” means any data collected about the mass, volume, flow rate, heat content, or carbon content of a fuel.

“Fuel gas system” means a system of compressors, piping, knock-out pots, mix drums, sulfur removal units and flaring units that collects fuel gas from one or more sources for treatment, and transports it to a stationary combustion unit.

“GJ” means gigajoules or billion joules.

“High heat value” or “HHV” means the amount of heat energy released by the combustion of a unit quantity of a fuel, including the latent heat of vaporization of water embedded in the fuel.

“Hydrogen plant” means a plant that produces hydrogen with steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other processes.

“Impregnated saw dust” means saw dust containing resins, preservatives or other substances derived from fossil fuels.

“Kiln” means thermally insulated chambers, or ovens, in which controlled temperature regimes are produced, used in the production of clinker, lime and other products, and which includes any associated preheater or precalciner devices.

“Lime kiln dust” or “LKD” means lime dust produced in the course of production of quick lime.

“Lime type” refers to three types of quicklime derived from limestone containing varying percentages of magnesium carbonate. The three lime types are:

- a) High calcium quicklime, which is derived from limestone containing 0 to 5 per cent magnesium carbonate.
- b) Magnesium quicklime, which is derived from limestone containing 5 to 35 per cent magnesium carbonate.

- c) Dolomitic quicklime, which is derived from limestone containing 35 to 46 per cent magnesium carbonate.

“Liquefied petroleum gas” (LPG) means a group of gaseous hydrocarbons derived from crude oil refining or natural gas fractionation, and includes propane, propylene, normal butane, butane, butylene, isobutene and isobutylene.

“Low heat content gas” means gases recovered from casing vents, vapor recovery systems, storage tanks and other components within the production process of crude oil, natural gas and petroleum products.

“Low Heat Value” or “LHV” means the heat energy released through the combustion of a unit quantity of fuel, excluding the latent heat of vaporization of water embedded in the fuel.

“Mass balance” - means the application of the law of conservation of mass to a facility, process or piece of equipment to determine emissions based on the difference in the input and output of a unit operation, where the accumulation and depletion of a substance are included in the calculations.

“Measurement uncertainty” means the scientific uncertainty associated with measuring of GHG emissions due to limitations of monitoring equipment or quantification methodologies.

“MJ” means mega joules or one million joules.

“Nameplate generating capacity” means the maximum rated electrical power output of a generator under specific conditions designated by the manufacturer, expressed in megawatts (MW) or kilowatts (kW).

“Net power generated” means the gross electricity generation minus station service or unit service electricity requirements, expressed in megawatt hours (MWh) per year. In the case of cogeneration, this value is intended to include internal consumption of electricity for the purposes of a production process, as well as power put on the grid.

“Non-calcined calcium oxide” is calcium oxide that remains in the clinker or CKD in the form of CaCO_3 and calcium oxide in the clinker or CKD that entered the kiln as a non-carbonate species.

“Non-calcined magnesium oxide” is magnesium oxide that remains in the clinker or CKD in the form of MgCO_3 and magnesium oxide in the clinker or CKD that entered the kiln as a non-carbonate species.

“Person” means the person mentioned in section 2 of the regulation.

“Pressure swing adsorption” or “PSA” means a gas purification process which selectively concentrates target gas molecules using porous, high surface area solid adsorbents and elevated pressure.

“PSA off-gas” or “tail-gas” means the impurity stream resulting from the sequential PSA pressurization/depressurization purification process.

“Prime mover” means the type of equipment such as an engine or water wheel that drives an electric generator. “Prime movers” include, but are not limited to, reciprocating engines, combustion or gas turbines, steam turbines, microturbines, and fuel cells.

“Process” means the intentional or unintentional reactions between substances or their transformation, including, but not limited to, the chemical or electrolytic reduction of metal ores, the thermal decomposition of substances, and the formation of substances for use as product or feedstock.

“Process emissions” means the emissions from industrial processes (e.g., cement production, ammonia production) involving chemical or physical transformations other than fuel combustion. For example, the calcination of carbonates in a kiln during cement production or the oxidation of methane in an ammonia process results in the release of process CO₂ emissions to the atmosphere. Emissions from fuel combustion to provide process heat are not part of process emissions, whether the combustion is internal or external to the process equipment.

“Process vent” means an opening where a gas stream is continuously or periodically discharged during normal operation.

“Purge gas” means nitrogen, carbon dioxide, liquefied petroleum gas, or natural gas used to maintain a non-explosive mixture of gases in a flare header or provide sufficient exit velocity to prevent regressive flame travel back into the flare header.

“Quicklime” means a substance that consists of oxides of calcium and magnesium resulting from the calcination of limestone other highly calcareous materials such as aragonite, chalk, coral, marble and shell.

“Refinery fuel gas” or “still gas” means gas generated at a petroleum refinery or any gas generated by a refinery process unit, and that is combusted separately or in any combination with any type of gas or used as a chemical feedstock.

“Sinter production” means a process that produces a fused aggregate of fine iron-bearing materials suited for use in a blast furnace. The sinter machine is composed of a continuous traveling grate that conveys a bed of ore fines and other finely divided iron-bearing material and fuel (typically coke breeze), a burner at the feed end of the grate for ignition, and a series of downdraft windboxes along the length of the strand to support downdraft combustion and heat sufficient to produce a fused sinter product.

“Small refiner” means any petroleum refiner who owns or operates a refinery that has a crude oil throughput capacity equal to or less than 55,000 barrels per day.

“Standard conditions” or “Standard Temperature and Pressure” or “STP” means either a temperature of 20 degrees Celsius and a pressure of 101.325 kPa, unless otherwise stated in the Standard Quantification Methods (Section 4) or the Technical Reference Documents (section 5).

“Sm³” means standard cubic metre - the amount of gas that would occupy a volume of one cubic metre if free of combined water at standard conditions.

“Steam reforming” means the process by which methane and other hydrocarbons in natural gas are converted into hydrogen and carbon monoxide by reaction with steam over a catalyst.

“Sulfur recovery unit” or “SRU” means a process unit that recovers elemental sulfur from gases that contain reduced sulfur compounds and other pollutants, usually by a vapor-phase catalytic reaction of sulfur dioxide and hydrogen sulfide.

“Supplemental firing” means an energy input to the cogeneration facility used only in the thermal process of a topping cycle plant, or in the electricity generating or manufacturing process of a bottoming cycle plant.

“Topping cycle plant” means a cogeneration plant in which the energy input to the plant is first used to produce electricity, and at least some of the reject heat from the electricity production process is then used to provide useful thermal output.

“Useful thermal output” means the thermal energy made available in a cogeneration system for use in any industrial or commercial process, heating or cooling application, or delivered to other end users, i.e., total thermal energy made available for processes and applications other than electrical generation.

“Waste derived fuel” within the meaning of Regulation 347 of the Revised Regulations of Ontario (General – Waste Management made under the Environmental Protection Act).

“Wastewater separator” means equipment used to separate oils and water from locations downstream of process drains.

3. Best Alternative Quantification Methods

The Regulation provides for the use of Best Alternative Quantification Methods. This section of the Guideline specifies the methods.

Best alternative quantification methods are any of the published methods included in the following list:

Best Alternative Quantification Method	Link
1. U.S. EPA, 40 CFR Part 98, Mandatory Greenhouse Gas Reporting, Subparts A to Subpart PP	http://www.epa.gov/climatechange/emissions/downloads09/GHG-MRR-Full%20Version.pdf
2. 2006 IPCC Guidelines for National Greenhouse Gas Inventories - Volume 3 -Industrial Processes and Product Use	http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol3.html

Best Alternative Quantification Method	Link
3. Environment Canada, Sector Specific Protocols and Guidance Manuals, posted on the Environment Canada website	http://www.ec.gc.ca/pdb/ghg/guidance/calcul_pro_e.cfm
4. CO ₂ Emissions Calculation Protocol for the Lime Industry—English Units Version, February 5, 2008 Revision—National Lime Association	Available for purchase from the National Lime Association (NLA), 200 North Glebe Road, Suite 800, Arlington, Virginia 22203, (703) 243-5463, http://www.lime.org
5. Methodology Manual – Estimation of Air Emissions from the Canadian Natural Gas Transmission, Storage and Distribution System, Prepared for Canadian Energy Partnership for Environmental Innovation (CEPEI), by Clearstone Engineering, September 25, 2007	
6. American Petroleum Institute (API) Compendium of GHG Emission Methodology for the Oil and Gas Industry, August 2009	http://www.api.org/ehs/climate/new/upload/2009_GHG_COMPENDIUM.pdf
7. CO ₂ Accounting and Reporting Standard for the Cement Industry, June 2005, Version 2.0, World Business Council for Sustainable Development	http://www.wbcsd.org/web/publications/cement-tf1.pdf
8. Calculation tools for Estimating Greenhouse Gas Emissions from Pulp and Paper Mills – Version 1.1, ICFPA/NCASI	http://www.ncasi.org/programs/areas/climate/ghgtools/pulp_icfpa.aspx

If the person is unable to use any of the best alternative quantification methods set out above, the person may apply to the Director for written consent to use an alternative method.

4. Standard Quantification Methods

Section 4(1) the Regulation specifies the need to use a standard quantification method in the Guideline. This section provides the listing of the standard

quantification methods that are to be used. Copies of the methods are provided in the appendix.

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Adipic Acid Manufacturing	ON.400	1
Primary Aluminum Manufacturing	U.S. EPA, 40 CFR 98, Subpart F, sections 98.60, 98.63 – 98.66	2
Ammonia Manufacturing	U.S. EPA, 40 CFR 98, Subpart G, sections 98.70, 98.73 – 98.76	3
Carbonates Use	U.S. EPA, 40 CFR 98, Subpart U, sections 98.210, 98.213 – 98.216	4
Cement Manufacturing	ON.90	5
Coal Storage	ON.100	6
Copper Production	ON.500	7
Electricity Generation and Cogeneration	ON.40	8
Ferroalloy Production	U.S. EPA, 40 CFR 98, Subpart K, sections 98.110, 98.113 – 98.116	9
General Stationary Combustion	ON.20	10
Glass Production	U.S. EPA, 40 CFR 98, Subpart N, sections 98.140, 98.143 – 98.146	11
HCFC-22 Production	U.S. EPA, 40 CFR 98, Subpart O, sections 98.150, 98.153 – 98.156	12
Hydrogen Production	ON.130	13
Iron Manufacturing	ON.150	14
Lead Production	ON.160	15
Lime Manufacturing	ON.170	16
Nickel Production	ON.500	17
Nitric Acid Manufacturing	U.S. EPA, 40 CFR 98, Subpart V sections 98.220, 98.223 – 98.226	18
Petrochemical Manufacturing	ON.300	19

Source of Greenhouse Gas	Standard Quantification Method	Appendix
Petroleum Refineries	ON.200	20
Phosphoric Acid Production	U.S. EPA, 40 CFR 98, Subpart Z, sections 98.260, 98.263 – 98.266	21
Pulp and Paper Manufacturing	ON.210	22
Refinery Fuel Gas Use within a Petroleum Refinery	ON.30	23
Soda Ash Manufacturing	U.S. EPA, 40 CFR 98, Subpart CC, sections 98.290, 98.293 – 98.296	24
Steel Manufacturing	ON.150	25
Zinc Production	ON.240	26

The procedure for interim fuel and other analytical data collection in the event of a breakdown in the data collection system is provided in section 25(f) of method ON.20 in Appendix 10 of this Guideline. This procedure applies to all sources and standard quantification methods in the Guideline.

5. Technical Reference Documents

All of the documents listed in the “Reference Title” column of the following table are incorporated into the Guideline as amended from time to time and where the Guideline requires the use of one of these methods, the most current version shall be used.

Reference Title	Website
Analytical Methods section of the National Lime Association ‘CO ₂ Emissions Calculation Protocol for the Lime Industry English Units Version’, February 5, 2008	http://www.climatevision.gov/sectors/lime/pdfs/lime_protocol.pdf
ASME Performance Test Codes	http://www.normas.com/ASME/pages/PTC.html
ASTM C114-09 - Standard Test Methods for Chemical Analysis of Hydraulic Cement	http://myastm.astm.org/DATABASE.CART/REDLINE_PAGES/C114.htm
ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime	http://www.astm.org/Standards/C25.htm

Reference Title	Website
ASTM D1826 - 94(2003) Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimetre	http://www.astm.org/Standards/D1826.htm
ASTM D1835 - 05 Standard Specification for Liquefied Petroleum (LP) Gases	http://www.astm.org/Standards/D1835.htm
ASTM D1945-03 (2006), Standard Test Method for Analysis of Natural Gas by Gas Chromatography	http://www.astm.org/Standards/D1945.htm
ASTM D1946-90 (2006), Standard Practice for Analysis of Reformed Gas by Gas Chromatography	http://www.astm.org/Standards/D1946.htm
ASTM D240 - 02(2007) Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimetre	http://www.astm.org/Standards/D240.htm
ASTM D2502-04 (2002), Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements	http://www.astm.org/Standards/D2502.htm
ASTM D2503-92 (2007), Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure	http://www.astm.org/Standards/D2503.htm
ASTM D3238-95 (2005), Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method	http://www.astm.org/Standards/D3238.htm
Analytical Methods section of the National Lime Association 'CO2 Emissions Calculation Protocol for the Lime Industry English Units Version', February 5, 2008	http://www.climatevision.gov/sectors/lime/pdfs/lime_protocol.pdf
ASME Performance Test Codes	http://www.normas.com/ASME/pages/PTC.html
ASTM C25-06 Standard Test Method for Chemical Analysis of Limestone, quicklime, and Hydrated Lime	http://www.astm.org/Standards/C25.htm

Reference Title	Website
ASTM D1826 – 94 Standard Test Method for Calorific (Heating) Value of Gases in Natural Gas Range by Continuous Recording Calorimetre	http://www.astm.org/Standards/D1826.htm
ASTM D1835 - 05 Standard Specification for Liquefied Petroleum (LP) Gases	http://www.astm.org/Standards/D1835.htm
ASTM D1945-03, Standard Test Method for Analysis of Natural Gas by Gas Chromatography	http://www.astm.org/Standards/D1945.htm
ASTM D1946-90, Standard Practice for Analysis of Reformed Gas by Gas Chromatography	http://www.astm.org/Standards/D1946.htm
ASTM D240 - 02 Standard Test Method for Heat of Combustion of Liquid Hydrocarbon Fuels by Bomb Calorimetre	http://www.astm.org/Standards/D240.htm
ASTM D2502-04, Standard Test Method for Estimation of Molecular Weight (Relative Molecular Mass) of Petroleum Oils from Viscosity Measurements.	http://www.astm.org/Standards/D2502.htm
ASTM D2503-92, Standard Test Method for Relative Molecular Mass (Relative Molecular Weight) of Hydrocarbons by Thermoelectric Measurement of Vapor Pressure.	http://www.astm.org/Standards/D2503.htm
ASTM D3238-95, Standard Test Method for Calculation of Carbon Distribution and Structural Group Analysis of Petroleum Oils by the n-d-M Method	http://www.astm.org/Standards/D3238.htm
ASTM D3588-98, Standard Practice for Calculating Heat Value, Compressibility Factor, and Relative Density of Gaseous Fuels	http://www.astm.org/Standards/D3588.htm
ASTM D4057-06, Standard Practice for Manual Sampling of Petroleum and Petroleum Products	http://www.astm.org/Standards/D4057.htm
ASTM D4891-89, Standard Test Method for Heating Value of Gases in Natural Gas Range by Stoichiometric Combustion	http://www.astm.org/Standards/D4891.htm

Reference Title	Website
ASTM D5291-02, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Petroleum Products and Lubricants	http://www.astm.org/Standards/D5291.htm
ASTM D5373-08, Standard Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke	http://www.astm.org/Standards/D5373.htm
ASTM D5468-02 - Standard Test Method for Gross Calorific and Ash Value of Waste Materials	http://www.techstreet.com/cgi-bin/detail?product_id=1372783
ASTM D5865-07a, Standard Test Method for Gross Calorific Value of Coal and Coke	http://www.astm.org/Standards/D5865.htm
ASTM D6348-03 - Standard Test Method for Determination of Gaseous Compounds by Extractive Direct Interface Fourier Transform Infrared (FTIR) Spectroscopy	http://www.techstreet.com/cgi-bin/detail?product_id=1144270
ASTM D6866-06a, Standard Test Methods for Determining the Biobased Content of Natural Range Materials Using Radiocarbon and Isotope Ratio Mass Spectrometry Analysis	http://www.astm.org/DATABASE.CART/HISTORICAL/D6866-06A.htm
ASTM D7459-08, Standard Practice for Collection of Integrated Samples for the Speciation of Biomass (Biogenic) and Fossil-Derived Carbon Dioxide Emitted from Stationary Emissions Sources	http://www.astm.org/Standards/D7459.htm
ASTM E1019-03, Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel and in Iron, Nickel, and Cobalt Alloys	http://www.astm.org/DATABASE.CART/HISTORICAL/E1019-03.htm
ASTM E1019-08 - Standard Test Methods for Determination of Carbon, Sulfur, Nitrogen, and Oxygen in Steel, Iron, Nickel, and Cobalt Alloys by Various Combustion and Fusion Techniques	http://www.techstreet.com/cgi-bin/detail?product_id=1590512
ASTM E351-93 - Standard Test Methods for Chemical Analysis of Cast Iron-All Types	http://www.techstreet.com/cgi-bin/detail?product_id=1271141

Reference Title	Website
ASTM-D5373-02 - Test Methods for Instrumental Determination of Carbon, Hydrogen, and Nitrogen in Laboratory Samples of Coal and Coke	http://www.techstreet.com/cgi-bin/detail?product_id=1501588
C1271-99 Standard Test Method for X-ray Spectrometric Analysis of Lime and Limestone	http://www.astm.org/Standards/C1271.htm
C1301-95 Standard Test Method for Major and Trace Elements in Limestone and Lime by Inductively Coupled Plasma-Atomic Emission Spectroscopy (ICP) and Atomic Absorption (AA).	http://www.astm.org/Standards/C1301.htm
CCME EPC-73: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993)	http://www.ccme.ca/assets/pdf/pn_1106_e.pdf
Environment Canada “Protocols and Performance specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7 dated December 2005	http://www.ec.gc.ca/cleanair-airpur/CAOL/electricity_Generation/protocols_performance/toc_e.cfm
Gas Processors Association (GPA) Standard 2261-00, Revised 2000	http://www.techstreet.com/cgi-bin/detail?product_id=861546
U.S. EPA Method 320 (40 CFR part 63, Appendix A)	http://www.epa.gov/ttn/emc/promgate/m-320.pdf
U.S. EPA TANKS Version 4.09D, U.S. Environmental Protection Agency, October 2005	http://www.epa.gov/ttnchie1/software/tanks/index.html#order

Appendices

Appendix 1 ON.400 Adipic Acid Manufacturing

ON.401 Source Category Definition

Adipic acid manufacturing consists of the oxidation of a mixture of cyclohexanone ((CH₂)₅CO) and cyclohexanol ((CH₂)₅CHOH) with nitric acid in the presence of a catalyst; nitrous oxide (N₂O) is formed as an unwanted by-product.

Adipic acid (HOOC(CH₂)₄COOH) is a dicarboxylic acid used in the production of a large number of products including synthetic fibers (primarily nylon 6,6), coatings, plastics, urethane foams, and synthetic lubricants.

ON.402 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for adipic acid manufacturing shall include the following information at the facility level calculated in accordance this method:

- a) Annual emissions of N₂O at the facility level expressed in tonnes/year
- b) Annual quantities of adipic acid production, tonnes/year
- c) Annual CO₂, N₂O, and CH₄ emissions from stationary combustion units not covered by this method shall follow the calculation methods and reporting requirements in ON.20.

ON.403 Calculation of N₂O Emissions

- a) Process N₂O emissions. Determine process N₂O emissions as specified under either paragraph (1) or (2) of this section.
 - (1) Continuous emissions monitoring systems (CEMS) or
 - (2) Calculation methodologies specified in paragraph (b) of this section.
- b) Process N₂O Emissions Calculation Methodology. Calculate total N₂O process emissions using the following equation:

$$E_{N_2O} = EF \times AAP \times (1 - DF \times ASUF) \quad \text{Equation 400-1}$$

Where:

E_{N_2O}	=	Emissions of N ₂ O from adipic acid production, tonnes/year
EF	=	N ₂ O emission factor (tonnes N ₂ O /tonne of adipic acid produced) derived from periodic emissions monitoring or sampling;
AAP	=	Adipic acid production, tonnes/year
DF	=	Destruction factor (dimensionless)
ASUF	=	Abatement system utilization factor (dimensionless)

ON.404 Sampling, Analysis, and Measurement Requirements

The following measurement methods shall be used.

- a) Facility N₂O emissions tests. All facilities must conduct testing using:
 - (1) U.S. EPA Method 320 (40 CFR part 63, Appendix A) annually; or
 - (2) ASTM D6348-03 annually; or
 - (3) CEMS to determine the uncontrolled emissions to derive an N₂O emission factor and abatement system destruction factor. The CEMS shall be operated in accordance with quality assurance and quality control program approved by the Director; or
 - (4) CEMS to determine the controlled N₂O emissions. The CEMS shall be operated in accordance with quality assurance and quality control program approved by the Director.
- b) Adipic acid production rates. Production rates may be determined through sales and accounting records, or through direct measurement using flow metres or weigh scales.

Appendix 2 Primary Aluminum Manufacturing

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart F sections 98.60, 98.63 – 98.66.

Appendix 3 Ammonia Manufacturing

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart G sections 98.70, 98.73 – 98.76.

Appendix 4 Carbonates Use

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart U sections 98.210, 98.213 – 98.216.

Appendix 5 ON.90 Cement Manufacturing

ON.91 Source Category Definition

Cement manufacturing is comprised of all processes that are used to manufacture Portland, natural, masonry, pozzolanic, or other hydraulic cements.

ON.92 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for cement manufacturing shall include the following information at the facility level calculated in accordance this method:

- a) Total emissions of CO₂, CH₄, and N₂O in tonnes.
- b) Annual CO₂ process emissions from calcination expressed in tonnes and the following information:
 - (1) Annual CO₂ emission factor for clinker, tonne/tonne clinker.
 - (2) Annual quantity of clinker produced expressed in tonnes.
 - (3) Annual CO₂ Emission factor for cement kiln dust (CKD) in tonne/tonne CKD not recycled back to kiln.
- c) Annual amount of feed consumed in the report year in tonnes and annual average feed to clinker conversion rate
- d) Annual CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in ON.93(c), tonnes.
- e) Annual CO₂, CH₄, and N₂O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in ON.20, tonnes.
- f) If a CEMS is used to measure CO₂ emissions from kilns, then the requirements of paragraphs (b), (c), and (d) of this section do not apply for CO₂. Cement plants that measure CO₂ emissions using CEMS shall report fuel usage by fuel type for kilns.

ON.93 Calculation of Greenhouse Gas Emissions From Kilns

- a) Determine CO₂ emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
 - (1) Use a CEMS that complies with the provisions in Report EPS 1/PG/7.

- (2) Calculate the sum of CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.
- b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions as the sum of emissions from calcination, using the method specified in paragraph (b)(1) of this section; and from organic carbon oxidation of feed, using the method specified in paragraph (b)(2) of this section (Equation 90-0).

$$E_{CO_2-P} = E_{CO_2-C} + E_{CO_2-F}$$

Equation 90-0

Where:

- E_{CO_2-P} = Annual process CO₂ emissions, tonne/year.
- E_{CO_2-C} = Annual process CO₂ emissions from calcination, tonne/year.
- E_{CO_2-F} = Annual process CO₂ emissions from feed oxidation, tonne/year.

- (1) Calcination Emissions. Calculate CO₂ process emissions from calcination using Equation 90-1 and a plant-specific clinker emission factor and a plant-specific cement kiln dust (CKD) emission factor as specified in this section.

$$E_{CO_2-C} = \sum_{i=1}^{12} Q_{Cli,i} \times EF_{Cli,i} + \sum_{j=1}^4 (Q_{CKD,j} \times EF_{CKD,j})$$

Equation 90-1

Where:

- E_{CO_2-C} = Annual CO₂ emissions from calcination, tonne/year.
- $Q_{Cli,i}$ = Quantity of clinker produced in month i, tonne/month.
- $EF_{Cli,i}$ = Clinker emission factor for month i, tonne CO₂/tonne clinker computed as specified in paragraph (b)(1)(A) of this section.
- $Q_{CKD,j}$ = Quantity CKD not recycled to the kiln in quarter j, tonne/quarter.
- $EF_{CKD,j}$ = CKD emission factor for quarter j, computed as specified in paragraph (b)(1)(B) of this section.

- (A) Clinker Emission Factor. Calculate a plant-specific clinker emission factor for each month using Equation 90-2.

$$EF_{Cli} = (CaO_{Cli} - CaO_f) \times 0.785 + (MgO_{Cli} - MgO_f) \times 1.092$$

Equation 90-2

Where:

EF_{Cli}	=	Monthly CO ₂ emission factor for clinker, tonne CO ₂ /tonne clinker
CaO_{Cli}	=	Monthly total calcium oxide content of clinker, tonne CaO/tonne clinker.
CaO_f	=	Monthly non-calcined calcium oxide content of clinker, tonne CaO/tonne clinker.
MgO_{Cli}	=	Monthly total magnesium oxide content of clinker, tonne MgO/tonne clinker.
MgO_f	=	Monthly non-calcined magnesium oxide content of clinker, tonne MgO/tonne clinker.
0.785	=	Ratio of molecular weights of CO ₂ to CaO
1.092	=	Ratio of molecular weights of CO ₂ to MgO

(B) CKD Emission Factor. If CKD is generated and not recycled back to the kiln, then calculate a plant-specific CKD emission factor based on quarterly sampling. The CKD emission factor shall be calculated using Equation 90-3.

$$EF_{CKD} = (CaO_{CKD} - CaO_f) \times 0.785 + (MgO_{CKD} - MgO_f) \times 1.092 \quad \text{Equation 90-3}$$

Where:

EF_{CKD}	=	Quarterly CO ₂ emission factor for CKD, tonne CO ₂ /tonne CKD not recycled back to kiln.
CaO_{CKD}	=	Quarterly total calcium oxide content of clinker, tonne CaO/tonne CKD.
CaO_f	=	Quarterly non-calcined calcium oxide content of CKD, tonne CaO/tonne CKD.
MgO_{CKD}	=	Quarterly total magnesium oxide content of CKD, tonne MgO/tonne CKD.
MgO_f	=	Quarterly non-calcined magnesium oxide content of CKD, tonne MgO/tonne CKD.
0.785	=	Ratio of molecular weights of CO ₂ to CaO
1.092	=	Ratio of molecular weights of CO ₂ to MgO

(2) Organic Carbon Oxidation Emissions. Calculate CO₂ process emissions from the total organic content in feed by using Equation 90-4.

$$E_{CO_2-F} = TOC_F \times F \times 3.664 \quad \text{Equation 90-4}$$

Where:

- E_{CO_2-F} = CO₂ emissions from feed oxidation, tonne.
- TOC_F = Total organic carbon content in feed, measured using the method in ON.94(b) or assumed a default value of 0.002, weight fraction.
- F = Annual amount of feed consumed, tonne.
- 3.664 = Ratio of molecular weights of carbon dioxide to carbon.

- c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O emissions from stationary fuel combustion following the calculation methods specified in ON.20. Cement plants that combust pure biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO₂ emissions from fossil fuels using the emission factor methodology in ON.23(a). “Pure” means that the biomass-derived fuels account for 97 per cent of the total amount of carbon in the fuels burned.

ON.94 Sampling, Analysis, and Measurement Requirements

- a) Determine the plant-specific weight fractions of total calcium expressed as calcium oxide and total magnesium expressed as magnesium oxide in clinker, CKD and in any non-carbonate source of calcium oxide entering the kiln using ASTM C114-09. The monitoring must be conducted monthly from clinker, non-carbonate source of calcium oxide and quarterly from CKD samples either directly from the process or drawn from bulk storage. The uncalcined CaO and MgO that remains in the clinker, CKD in the form of CaCO₃ and MgCO₃, or that enters the kilns as non-carbonate species may be assumed to be a default value of 0.0; or may be determined by chemical analysis of feed material and clinker material from each kiln using documented analytical and calculation methods or the appropriate industry standard practice.
- b) The total organic carbon contents of feed must be determined annually using ASTM C114-09.
- c) The quantity of clinker produced must be determined by either:
- i. direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders, or
 - ii. Material balance, using plant specific feed to clinker conversion; cement deliveries and usage of other materials; as approved by the Director.

- d) The quantity of CKD not recycled back to kiln must be determined by either:
 - i. direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders, or
 - ii. Material balance, using plant specific feed to clinker conversion; cement deliveries and usage of other materials; as approved by the Director.
- e) The quantity of feed consumed (i.e. limestone, fly ash, sand, shale, iron oxide, and alumina) must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Appendix 6 ON.100 Coal Storage

ON.101 Source Category Definition

Coal storage piles are located at any facilities that combust coal. Coal storage piles release fugitive methane (CH₄) emissions.

Fugitive Emissions

Within natural coal deposits, CH₄ is either trapped under pressure within porous void spaces or adsorbed to the coal. Coal mining, post-mining activities, and coal-handling activities release pressurized CH₄ to the atmosphere; adsorbed CH₄ is also released until the CH₄ in the coal reaches equilibrium with the surrounding atmospheric conditions.

ON.102 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for coal storage shall include the following information at the facility level calculated in accordance this method:

- a) Annual greenhouse gas emissions, reported as follows:
 - (1) Total CH₄ emissions expressed in tonnes/year.
- b) Annual coal purchases expressed in tonnes/year

ON.103 Calculation of CH₄ Emissions

Calculate fugitive CH₄ emissions from coal storage piles as specified in paragraph (a), (b), or (c) of this section.

- a) For coal purchased from U.S. sources, calculate fugitive CH₄ emissions using Equation 100-1 and Table 100-1.
- b) For coal purchased from Canadian sources, calculate fugitive CH₄ emissions using Equation 100-1 and Table 100-2.
- c) For coal purchased from non-U.S. and non-Canadian sources, the person should use either ON.103(a) or ON.103(b), whichever is the most applicable for the type of coal used. This chosen approach is subject to approval by Director.

$$E_{CH_4} = \sum_i (PC_i \times EF_i) \times 0.6772 \times 0.001$$

Equation 100-1

Where:

E_{CH_4}	=	Fugitive emissions from coal storage piles for each coal category in, tonnes CH_4 /year
PC_i	=	Purchased coal for each coal category i, tonnes/year
EF_i	=	Default CH_4 emission factor for each coal category i specified by location and mine type that coal originated from, provided in Table 100-1 or Table 100-2, $m^3 CH_4$ /tonne of coal
0.6772	=	Methane density, kg/ m^3 at 15°C and 101.325 kilopascal
0.001	=	Conversion factor from kg to tonnes

ON.104 Sampling, Analysis, and Measurement Requirements

a) Coal Purchase Monitoring Requirements.

Facilities may determine the quantity of coal purchased either using records provided by the coal supplier(s) or by monitoring coal purchase quantities using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 100-1. U.S. Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH ₄ m ³ per Tonne)			
Coal Origin		Coal Mine Type	
Coal Basin	States	Surface Post-Mining Factors	Underground Post-Mining Factors
Northern Appalachia	Maryland, Ohio, Pennsylvania, West Virginia North	0.6025	1.4048
Central Appalachia (WV)	Tennessee, West Virginia South	0.2529	1.3892
Central Appalachia (VA)	Virginia	0.2529	4.0490
Central Appalachia (E KY)	East Kentucky	0.2529	0.6244
Warrior	Alabama, Mississippi	0.3122	2.7066
Illinois	Illinois, Indiana, Kentucky West	0.3465	0.6525
Rockies (Piceance Basin)	Arizona, California, Colorado, New Mexico, Utah	0.3372	1.9917
Rockies (Uinta Basin)		0.1623	1.0083
Rockies (San Juan Basin)		0.0749	1.0645
Rockies (Green River Basin)		0.3372	2.5068
Rockies (Raton Basin)		0.3372	1.2987
N. Great Plains	Montana, North Dakota, Wyoming	0.0562	0.1592
West Interior (Forest City, Cherokee Basins)	Arkansas, Iowa, Kansas, Louisiana, Missouri, Oklahoma, Texas	0.3465	0.6525
West Interior (Arkoma Basin)		0.7555	3.3591
West Interior (Gulf Coast Basin)		0.3372	1.2987
Northwest (AK)	Alaska	0.0562	1.6233
Northwest (WA)	Washington	0.0562	0.5900
Source: <i>Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990 – 2005</i> April 15, 2007, U.S. Environmental Protection Agency. Annex 3, Methodological Descriptions for Additional Source or Sink Categories, Section 3.3, Table A-115, Coal Surface and Post-Mining CH ₄ Emission Factors (ft ³ per Short Ton; converted to m ³ per tonne). (Only Post-Mining EFs used from Table). State assignments shown from Table 113 of Annex 3.			

Table 100-2. Canada Default Fugitive Methane Emission Factors from Post-Mining Coal Storage and Handling (CH ₄ m ³ per tonne)			
Coal Origin		Coal Mine Type	
Province	Coalfield	Surface Post-Mining Factors	Underground Post-Mining Factors
British Columbia	Comox	0.500	n/a
	Crowness	0.169	n/a
	Elk Valley	0.900	n/a
	Peace River	0.361	n/a
	Province Average	0.521	n/a
Alberta	Battle River	0.067	n/a
	Cadomin-Luscar	0.709	n/a
	Coalspur	0.314	n/a
	Obed Mountain	0.238	n/a
	Sheerness	0.048	n/a
	Smokey River	0.125	0.067
	Wabamun	0.176	n/a
	Province Average	0.263	0.067
Saskatchewan	Estavan	0.055	n/a
	Willow Bunch	0.053	n/a
	Province Average	0.054	n/a
New Brunswick	Province Average	0.060	n/a
Nova Scotia	Province Average	n/a	2.923
Source: <i>Management of Methane Emissions from Coal Mines: Environmental, Engineering, Economic and Institutional Implications of Options</i> . Prepared by Brian G. King, Neill and Gunter (Nova Scotia) Limited, Dartmouth, Nova Scotia for Environment Canada. Contract Number K2031-3-7062. March 1994. This document is cited by Environment Canada in the NIR 1990-2007 (Final Submission, April 2009), but post-mining emission factors are not provided, so they were developed for WCI purposes by Province. Surface emission factors were derived from Table 3.1 (Coal production statistics [Column A] and post-mining emissions [Column F]). Underground emission factors were derived from Table 3.2 (Coal production statistics and post-mining emissions).			

Appendix 7 ON.500 Copper and Nickel Production

ON.501 Source Category Definition

The nickel and copper metal production category includes process-related sources at nickel and copper metal smelting and refining facilities. Metals addressed in other categories (i.e., iron and steel, ferroalloys, aluminum, magnesium, lead, and zinc) are not included in this category.

The nickel and copper metal production category includes three main processes that produce CO₂ emissions: removal of impurities from nickel or copper ore concentrate using carbonate flux reagents (e.g., limestone [CaCO₃] or dolomite [CaCO₃·MgCO₃]), the use of other reducing agents to extract metals from their oxides (e.g., metallurgical coke, coal, natural gas, etc.), the use of material (e.g., coke) for slag cleaning and the consumption of graphite or carbon electrodes in electric arc furnaces. It is important to distinguish between fuels used for combustion and fuels used as reducing agents; only fuels used as reducing agents should be included in the base metal production category. Fuels used for combustion are reported in ON.20.

ON.502 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for copper and nickel production shall include the following information at the facility level calculated in accordance this method:

- a) Annual emissions of CO₂ at the facility level, tonnes/year
- b) Annual quantities of each carbonate flux reagent used, tonnes/year
- c) Fractional purity of each carbonate flux reagent used, tonnes carbonate/tonne raw material
- d) Annual quantities of other reducing agents used, tonnes/year
- e) Carbon content of other reducing agent used or material used for slag cleaning, tonnes C/tonne reducing agent or material for slag cleaning
- f) Annual quantity of ore processed, tonnes/year
- g) Carbon content of ore processed, tonnes C/tonne ore
- h) Annual CO₂, N₂O, and CH₄ emissions from stationary combustion units not covered by this method shall follow the calculation methods and reporting requirements in ON.20.

ON.503 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a), (b), and (c) of this section.

- a) Calculate CO₂ emissions from carbonate flux reagents using Equation 500-1.

$$E_{CO_{2cf}} = Q_{ls} \times f_{ls} \times \left(\frac{44}{100} \right) + Q_d \times f_d \times \left(\frac{88}{184} \right)$$

Equation 500-1

Where:

$E_{CO_{2cf}}$	=	Annual CO ₂ emissions from carbonate flux reagents, tonnes/year
Q_{ls}	=	Annual quantity of limestone consumed, tonnes/year
f_{ls}	=	Calcium carbonate content of the limestone, tonnes CaCO ₃ /tonne of raw material
44/100	=	ratio of molecular weight, carbon dioxide to calcium carbonate
Q_d	=	Annual quantity of dolomite consumed, tonnes/year
f_d	=	Calcium Carbonate and Magnesium Carbonate content of the dolomite, tonnes CaCO ₃ ·MgCO ₃ /tonne of raw material
88/184	=	Ratio of molecular weight, CO ₂ to CaCO ₃ ·MgCO ₃

- b) Calculate CO₂ emissions from other reducing agents or material used in slag cleaning using Equations 500-2 and 500-3. Calculation accounts for any carbon that may exist in the metal ore.

$$E_{CO_{2ra}} = \left(\sum_a [Q_a \times EF_a] \right) + Q_{ore} \times C_{ore} \times 3.664$$

Equation 500-2

$$EF_a = C_a \times 3.664$$

Equation 500-3

Where:

$E_{CO_{2ra}}$	=	CO ₂ emissions from other reducing agents or slag cleaning, tonnes/year
Q_a	=	Quantity of other reducing agent or material used for slag cleaning, tonnes/year
EF_a	=	Site specific emission factor for reducing agent or material used for slag cleaning, tonnes CO ₂ /tonne of reducing agent a
C_a	=	Carbon content of other reducing agent or material used for slag cleaning tonnes C/tonne of reducing agent or material used for slag cleaning

Q_{ore}	=	Annual quantity of nickel or copper metal ore consumed, tonnes/year
C_{ore}	=	Carbon content of base metal ore, tonnes C/metric tonne of base metal ore
3.664	=	ratio of molecular weight, carbon dioxide to carbon.

- c) Calculate CO₂ emissions from carbon electrode consumption in electric arc furnaces (EAFs) using Equation 500-4.

$$E_{CO_2ce} = Q_{ce} \times C_{ce} \times 3.664$$

Equation 500-4

Where:

E_{CO_2ce}	=	Annual CO ₂ emissions from carbon electrode consumption in EAFs, tonnes/year
Q_{ce}	=	Quantity of carbon electrodes consumed, tonnes/year
C_{ce}	=	Carbon content of carbon electrodes, tonnes C/metric tonne carbon electrodes
3.664	=	ratio of molecular weights, carbon dioxide to carbon.

ON.504 Sampling, Analysis, and Measurement Requirements

Reducing agent carbon content shall be determined as specified under paragraph (a), (b), or (c) of this section.

- a) Carbon contents from reducing agents or material for slag cleaning should be determined in the following manner:
 - (1) For coal and coke, use ASTM D5373-02.
 - (2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 or computations based on ASTM D3238-95 and either ASTM D2502-04 or ASTM D2503-92.
 - (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90.
- b) Carbon contents of carbon electrodes should be obtained from the electrode vendor or supplier.
- c) Carbon contents from carbonate flux reagents (i.e., limestone and dolomite) should be determined using ASTM C25-06.

Appendix 8 ON.40 Electricity Generation and Cogeneration

ON.41 Source Category Definition

An electricity generating unit is any combustion device that combusts solid, liquid, or gaseous fuel for the purpose of producing electricity either for sale or for use onsite. This source category includes cogeneration (combined heat and power) units.

ON.42 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for electricity generation and cogeneration shall include the following information at the facility level calculated in accordance this method:

- a) Annual greenhouse gas emissions in tonnes, reported as follows:
 - (1) Total CO₂ emissions for fossil fuels, reported by fuel type in tonnes.
 - (2) Total CO₂ emissions for all biomass fuels combined in tonnes.
 - (3) Total CH₄ emissions for fuels combined in tonnes.
 - (4) Total N₂O emissions for all fuels combined in tonnes.
 - (5) Total emissions of each of the HFCs in Table 1 of the Regulation, tonnes.
- b) Annual fuel consumption:
 - (1) For gases, report in units of Sm³.
 - (2) For liquids, report in units of kilolitres.
 - (3) For non-biomass solids, report in units of tonnes.
 - (4) For biomass-derived solid fuels, report in units of bone dry tonnes.
- c) The nameplate generating capacity in megawatts and net power generated in the reporting year in megawatt hours.
- d) For each cogeneration unit, indicate whether topping or bottoming cycle and provide useful thermal output as applicable, in MJ. Where steam or heat is acquired from another facility for the generation of electricity, report the provider and amount of acquired steam or heat in MJ. Where supplemental firing has been applied to support electricity generation or industrial output, report this purpose and fuel consumption by fuel type using the units in ON.42(b).
- e) Process CO₂ emissions from acid gas scrubbers and acid gas reagent.
- f) Fugitive emissions of HFC from cooling units that support power generation.

- g) Fugitive CO₂ emissions from geothermal facilities.
- h) Fugitive CO₂ emissions from coal storage at coal-fired electricity generating facilities shall be reported as specified in section ON.100.

ON.43 Calculation of Greenhouse Gas Emissions

- a) Calculation of CO₂ Emissions. The person shall use continuous emissions monitoring systems (CEMS) to measure CO₂ emissions if required to operate a CO₂ CEMS and a stack gas flow rate monitor by any other federal or provincial regulation. The person that is not required to operate a CEMS under another reporting program may use either CEMS or the calculation methods specified in paragraphs (a)(1) through (a)(7). The person using CEMS to determine CO₂ emissions shall comply with the provisions in section ON.23(d).
 - (1) Natural Gas. For electric generating units combusting natural gas, use one of the following methods:
 - (A) If the high heat value is greater than or equal to 0.0363 and less than or equal to 0.04098 GJ/Sm³ use either:
 - i. The measured carbon content of the fuel and calculation methodology 3 in section ON.23(c); or
 - ii. The measured heat content of the fuel and the calculation methodology 2 in section ON.23(b).
 - (B) If the high heat value is less than 0.0363 or greater than 0.04098 GJ/Sm³, use the measured carbon content of the fuel and the calculation methodology 3 in section ON.23(c).
 - (2) Coal or Petroleum Coke. For electric generating units combusting coal or petroleum coke, use the measured carbon content of the fuel and calculation methodology 3 in section ON.23(c).
 - (3) Middle Distillates, Gasoline, Residual Oil, or Liquid Petroleum Gases. For electric generating units combusting middle distillates (such as diesel, fuel oil, or kerosene), gasoline, residual oil, or LPG (such as ethane, propane, isobutene, n-butane, or unspecified LPG), use one of the following methods:
 - (A) The measured carbon content of the fuel and calculation methodology 3 in section ON.23(c); or
 - (B) The measured heat content of the fuel and calculation methodology 2 in section ON.23(b).
 - (4) Refinery Fuel Gas, Flexigas, or Associated Gas. For electric generating units combusting refinery fuel gas, flexigas, or associated gas, use the methods specified in ON.30.
 - (5) Landfill Gas, Biogas, or Biomass. For electric generating units combusting landfill gas, biogas, or biomass, use one of the following methods:

- (A) The measured carbon content of the fuel and calculation methodology 3 provided in section ON.23(c); or
 - (B) The measured heat content of the fuel and calculation methodology 2 in section ON.23(b).
- (6) Municipal Solid Waste. Electric generating units combusting municipal solid waste, may use the measured steam generated, the default emission factor in ON.20 Table 20-7, and the calculation methodology in section ON.23(b)(2) provided the facility is not subject to the verification requirements of the Regulation. If the facility is subject to the verification requirements of the Regulation, the person shall use CEMS to measure CO₂ emissions in accordance with ON.23(d), or calculate emissions using steam flow and a CO₂ emission factor according to the provisions of ON.23(c)(2).
- (7) Start-up Fuels. Persons responsible for generating facilities that primarily combust biomass-derived fuels but combust fossil fuels during start-up, shut-down, or malfunction operating periods only, shall calculate CO₂ emissions from fossil fuel combustion using one of the following methods:
- (A) The default emission factors from Tables 20-2, 20-3, 20-5 or 20-7, as applicable, and calculation methodology 1 provided in section ON.23(a);
 - (B) The measured heat content of the fuel and calculation methodology 2 provided in section ON.23(b);
 - (C) The measured carbon content of the fuel and calculation methodology 3 provided in section ON.23(c); or
 - (D) For combustion of refinery fuel gas, the measured heat content and carbon content of the fuel, and the calculation methodology provided in section ON.30.
- (8) Co-fired Electricity Generating Units. For electricity generating units that combust more than one type of fuel, the person shall calculate CO₂ emissions as follows.
- (A) For co-fired electricity generators that burn only fossil fuels, CO₂ emissions shall be determined using one of the following methods:
 - i. A CEMS in accordance with calculation methodology 4 in section ON.23(d). Persons using this method need not report emissions separately for each fossil fuel.
 - ii. For units not equipped with a CEMS, calculate the CO₂ emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(4) of this section.
 - (B) For co-fired electricity generators that burn biomass-derived fuel with a fossil fuel, CO₂ emissions shall be determined using one of the following methods:
 - i. A CEMS in accordance with calculation methodology 4 in section ON.23(d). Persons using this method shall

- determine the portion of the total CO₂ emissions attributable to the biomass-derived fuel and portion of the total CO₂ emissions attributable to the fossil fuel using the methods specified in section ON.23(d)(4) or
- ii. Calculate the CO₂ emissions separately for each fuel type using the methods specified in paragraphs (a)(1) through (a)(7) of this section.
 - b) Calculation of CH₄ and N₂O Emissions. Persons responsible for electricity generating units shall use the methods specified in section ON.24 to calculate the annual CH₄ and N₂O emissions. For coal combustion, use the default CH₄ emission factor(s) in Table 20-6 of ON.20.
 - c) Calculation of CO₂ Emissions from Acid Gas Scrubbing. Persons responsible for electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall calculate the annual CO₂ emissions from these processes using Equation 40-1 if these emissions are not already captured in CO₂ emissions determined using a CEMS.

$$E_{CO_2} = S \times R_{ca} \times R_{as} \times (MW_{CO_2} / MW_{Sorbent}) \quad \text{Equation 40-1}$$

Where:

E_{CO_2}	=	CO ₂ emitted from sorbent for the report year, tonnes/year
S	=	Limestone or other sorbent used in the report year, tonnes/year
R_{ca}	=	Ratio of moles of CO ₂ released upon capture of one mole of acid gas (equal to 1 for calcium carbonate sorbent)
R_{as}	=	Ratio of moles of acid gas captured to mole of sorbent used
MW_{CO_2}	=	Molecular weight of carbon dioxide, 44 grams/mole
$MW_{Sorbent}$	=	Molecular weight of sorbent, equal to 100 grams/mole if calcium carbonate

- d) Calculating Fugitive HFC Emissions from Cooling Units. Persons responsible for electricity generating facilities shall calculate fugitive HFC emissions for each HFC compound used in cooling units that support power generation or are used in heat transfers to cool stack gases using either the methodology in paragraph (d)(1) or (d)(2). The person is not required to report GHG emissions from air or water cooling systems or condensers that do not contain HFCs.

(1) Use Equation 40-2 to calculate annual HFC emissions for each of the HFCs in Table 3-1 of the Guideline:

$$HFC = (HFC_i + HFC_{p/a} + HFC_{s/d} + HFC_{cap}) \times 0.001 \quad \text{Equation 40-2}$$

Where:

- HFC = Annual fugitive HFC emission, tonnes;
- HFC_i = The difference between the quantity of HFC in storage at the beginning of the year and the quantity in storage at the end of the year. Stored HFC includes HFC contained in cylinders (such as 115-pound storage cylinders), gas carts, and other storage containers. It does not include HFC gas held in operating equipment. The change in inventory will be negative if the quantity of HFC in storage increases over the course of the year, kg
- $HFC_{p/a}$ = The sum of all HFC acquired from other entities during the year either in storage containers or in equipment, kg
- $HFC_{s/d}$ = The sum of all the HFC sold or otherwise transferred offsite to other entities during the year either in storage containers or in equipment, kg.
- HFC_{cap} = The net change in the total nameplate capacity (i.e. the full and proper charge) of the cooling equipment). The net change in capacity will be negative if the total nameplate capacity at the end of the year is less than the total nameplate capacity at the beginning of the year, kg
- 0.001 = conversion factor from kg to tonnes

- (2) Use service logs to document HFC usage and emissions from each cooling unit. Service logs should document all maintenance and service performed on the unit during the report year, including the quantity of HFCs added to or removed from the unit, and include a record at the beginning and end of each report year. The person may use service log information along with the following simplified material balance equations to quantify fugitive HFCs from unit installation, servicing, and retirement, as applicable. The person shall include the sum of HFC emissions from the applicable equations in the greenhouse gas emissions data report.

$$HFC_{Install} = R_{new} - C_{new}$$

$$HFC_{Service} = R_{recharge} - R_{Recover}$$

$$HFC_{Retire} = C_{retire} - R_{retire}$$

Where:

$HFC_{Install}$	=	HFC emitted during initial charging/installation of the unit, kg;
$HFC_{Service}$	=	HFC emitted during use and servicing of the unit for the report year, kg;
HFC_{Retire}	=	HFC emitted during the removal from service/retirement of the unit, kg;
R_{new}	=	HFC used to fill new unit (omit if unit was pre-charged by the manufacturer), kg;
C_{new}	=	Nameplate capacity of new unit (omit if unit was pre-charged by the manufacturer), kg;
$R_{recharge}$	=	HFC used to recharge the unit during maintenance and service, kg;
$R_{recover}$	=	HFC recovered from the unit during maintenance and service, kg;
C_{retire}	=	Nameplate capacity of the retired unit, kg; and
R_{retire}	=	HFC recovered from the retired unit, kg.

- e) Fugitive CO₂ Emissions from Geothermal Facilities. Persons responsible for geothermal electricity generating facilities shall calculate the fugitive CO₂ emissions using one of the following methods:

(1) Calculate the fugitive CO₂ emissions using Equation 40-3:

$$E_{CO_2} = EF \times Heat \times 0.001 \quad \text{Equation 40-3}$$

Where:

E_{CO_2}	=	CO ₂ emissions (tonnes/year)
EF	=	Default fugitive CO ₂ emission factor of 7.14 or measured values using ON.44(c), kg/GJ
Heat	=	Heat taken from geothermal steam and/or fluid, GJ/year
0.001	=	conversion factor from kg to tonnes

(2) Calculate CO₂ emissions using Director approved source specific emission factor.

ON.44 Sampling, Analysis, and Measurement Requirements

- a) CO₂, CH₄ and N₂O Emissions from Fuel Combustion. Persons using CEMS to estimate CO₂ emissions from fuel combustion shall comply with the

requirements in section ON.23(d). Persons using methods other than CEMS shall comply with the applicable fuel sampling, fuel consumption monitoring, heat content monitoring, and carbon content monitoring specified in section ON.25.

- b) CO₂ Emissions from Acid Gas Scrubbing. Persons responsible for electricity generating units that use acid gas scrubbers or add an acid gas reagent to the combustion unit shall measure the amount of limestone or other sorbent used during the reporting year.
- c) CO₂ Emissions from Geothermal Facilities. Persons responsible for geothermal facilities shall measure the heat recovered from geothermal steam. If using source specific emission factor instead of the default factor, the person shall conduct an annual test of the CO₂ emission rate. The person shall submit a pretest plan to the Director in the first year. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

Appendix 9 Ferroalloy Production

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart K, sections 98.110, 98.113 – 98.116.

Appendix 10 ON.20 General Stationary Combustion

ON.21 Source Category Definition

General stationary fuel combustion sources are devices and units that combust solid, liquid, or gaseous fuel for the purpose of generating steam (or providing useful heat or energy) for industrial, commercial, or institutional use; for pollution control; or reducing the volume of waste by removing combustible matter. General stationary combustion sources are boilers, kilns, furnaces, combustion turbines, internal combustion engines, incinerators, process heaters, and any other stationary combustion device that is not specifically addressed under the provisions for another source category in this Guideline.

ON.22 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for general stationary combustion shall include the following information at the facility level calculated in accordance this method:

- a) Annual greenhouse gas emissions in tonnes, reported as follows:
 - (1) Total CO₂ emissions (tonnes/year) for fossil and biomass fuels, reported by fuel type.
 - (2) Total CH₄ emissions (tonnes/year) reported for fossil and biomass by fuel type.
 - (3) Total N₂O emissions (tonnes/year) reported for fossil and biomass by fuel type.
- b) Annual fuel consumption:
 - (4) For gases, report in units of Sm³.
 - (5) For liquids, report in units of kilolitres.
 - (6) For non-biomass solids, report in units of tonnes.
 - (7) For biomass solid fuels, report in units of bone dry tonnes.
- c) Annual steam generation in kg, for units that burn biomass fuels or municipal solid waste.

ON.23 Calculation of CO₂ Emissions

For each fuel type, calculate CO₂ emissions using one of the four calculation methodologies specified in this section, subject to the restrictions in §ON.23(e).

Use of the Four CO₂ Calculation Methodologies. Use of the four CO₂ emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

- (1) Calculation Methodology 1 may not be used by a facility that is subject to the verification requirements of the Regulation, except for stationary combustion units that combust natural gas with a high heat value between 0.0363 and 0.04098 GJ/Sm³.
 - (2) Calculation Methodology 2 may not be used by a facility that is subject to the verification requirements of the Regulation, except for stationary combustion units that combust natural gas with a high heat value between 0.0363 and 0.04098 G J/Sm³ and biomass solid fuels.
 - (3) Calculation Methodology 3 may be used for a unit of any size combusting any type of fuel, except when the use of Calculation Methodology 4 is required.
 - (4) Calculation Methodology 4 may be used for a unit of any size combusting any type of fuel, and must be used for a combustion unit with a CO₂ CEMS and stack gas flow rate monitor that is required by any federal or provincial regulation.
- (a) Calculation Methodology 1. Calculate the annual CO₂ mass emissions by substituting a fuel-specific default CO₂ emission factor, a default high heat value, and the annual fuel consumption into Equation 20-1:

$$E_{CO_2} = Fuel \times HHV \times EF \times 0.001 \quad \text{Equation 20-1}$$

Where:

E_{CO_2}	=	Annual CO ₂ mass emissions for the specific fuel type, tonnes/year.
Fuel	=	Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in Sm ³ for gaseous fuel, and volume in kilolitres for liquid fuel).
HHV	=	Default high heat value of the fuel, from Table 20-1 .
EF	=	Fuel-specific default CO ₂ emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable, kg CO ₂ /GJ.
0.001	=	Conversion factor from kilograms to tonnes.

- (b) Calculation Methodology 2. Calculate the annual CO₂ mass emissions using a default fuel-specific CO₂ emission factor, a high heat value provided by the supplier or measured by the person using Equation 20-2, except for emissions from the combustion of biomass fuels and municipal solid waste, for which the person may instead elect to use the method shown in Equation 20-3.

- (1) For any type of fuel for which an emission factor is provided in Tables 20-2, 20-3, 20-5, or 20-7, as applicable, use Equation 20-2:

$$CO_2 = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.001 \quad \text{Equation 20-2}$$

Where:

CO ₂	=	Annual CO ₂ emissions for a specific fuel type, tonnes/year.
n	=	Number of required heat content measurements for the year as specified in ON.25(a).
Fuel _p	=	Mass or volume of the fuel combusted during the measurement period “p” (express mass in tonnes for solid fuel, volume in Sm ³ for gaseous fuel, and volume in kiloliters for liquid fuel).
HHV _p	=	High heat value of the fuel for the measurement period provided by the supplier or measured by the person, GJ/tonne for solid fuel, GJ/kilolitre for liquid fuel, or GJ/Sm ³ for gaseous fuel.
EF	=	Fuel-specific default CO ₂ emission factor, from Tables 20-2, 20-3, 20-5, or 20-7, as applicable, kg CO ₂ /GJ.
0.001	=	Conversion factor from kilograms to tonnes.

- (2) For biomass solid fuels and municipal solid waste, use either Equation 20-2 or Equation 20-3:

$$E_{CO_2} = Steam \times B \times EF \times 0.001 \quad \text{Equation 20-3}$$

Where:

E _{CO₂}	=	Annual CO ₂ emissions from solid biomass fuel or solid municipal waste combustion, tonnes/year.
Steam	=	Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year, tonnes steam/year.
B	=	Ratio of the boiler’s design rated heat input capacity to its design rated steam output capacity, GJ/tonne steam.
EF	=	Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or Table 20-7, as applicable, kg CO ₂ /GJ.
0.001	=	Conversion factor from kilograms to tonnes.

- (c) Calculation Methodology 3. Calculate the annual CO₂ mass emissions by using measurements of fuel carbon content or molar fraction (for gaseous fuels only), conducted by the person or provided by the fuel supplier, and the quantity of fuel combusted, using Equation 20-4, 20-5, 20-6 or 20-7 as applicable. For emissions from the combustion of biomass fuels and municipal solid waste, the person may instead elect to use the method shown in Equation 20-5.

- (1) For a solid fuel, use Equation 20-4 of this section:

$$E_{CO_2} = \sum_{i=1}^n Fuel_i \times CC_i \times 3.664 \quad \text{Equation 20-4}$$

Where:

- E_{CO_2} = Annual CO₂ emissions from the combustion of the specific solid fuel, tonnes/year.
- n = Number of carbon content measurements determinations for the year as specified in ON.25(a).
- $Fuel_i$ = Mass of the solid fuel combusted in measurement period “i” (tonnes for municipal solid waste, bone dry tonnes for biomass).
- CC_i = Carbon content of the solid fuel, from the fuel analysis results for measurement period “i” (per cent by weight, expressed as a decimal fraction, e.g., 95% = 0.95).
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon.

- (2) For biomass solid fuels or municipal solid waste, use either Equation 20-4 above or Equation 20-5:

$$E_{CO_2} = Steam \times B \times EF \times 0.001 \quad \text{Equation 20-5}$$

Where:

- E_{CO_2} = Annual CO₂ emissions from biomass solid fuel or municipal solid waste combustion, tonnes/year.
- Steam = Total mass of steam generated by biomass solid fuel or municipal solid waste combustion during the reporting year, tonnes steam/year.
- B = Ratio of the boiler’s design rated heat input capacity to its design rated steam output capacity, GJ per hour/tonnes steam per hour.
- EF = Default emission factor for biomass solid fuel or municipal solid waste, from Table 20-2 or 20-7, as applicable (kg CO₂/GJ), adjusted no less often than every third year as provided in ON.25(a)(5)(B).
- 0.001 = Conversion factor from kilograms to tonnes.

(3) For a liquid fuel, use Equation 20-6 of this section:

$$E_{CO_2} = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \quad \text{Equation 20-6}$$

Where:

- E_{CO_2} = Annual CO₂ emissions from the combustion of the specific liquid fuel, tonnes/year.
- n = Number of required carbon content determinations for the year, as specified in ON.25(a).
- $Fuel_i$ = Volume of the liquid fuel combusted in measurement period “i”, kilolitres.
- CC_i = Carbon content of the liquid fuel, from the fuel analysis results for measurement period “i”, tonnes Carbon/kilolitre of fuel.
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon.

(4) For a gaseous fuel, use Equation 20-7 of this section:

$$E_{CO_2} = \sum_{i=1}^n 3.664 \times Fuel_i \times CC_i \times d_i \times 0.001 \quad \text{Equation 20-7}$$

Where:

- E_{CO_2} = Annual CO₂ mass emissions from combustion of the specific gaseous fuel, tonnes/year.
- N = Number of required carbon content and molecular weight determinations for the year, as specified in ON.25(a).
- $Fuel_i$ = Volume of the gaseous fuel combusted in period “i”, as specified in ON.25(a), Sm³.
- CC_i = Average carbon content of the gaseous fuel, from the fuel analysis results for the period “i”, as specified in ON.25(a), kg C/kg of fuel.
- d_i = density of the gaseous fuel from fuel analysis or derive from mole fraction analysis, kg/Sm³.
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon.
- 0.001 = Conversion factor from kilograms to tonnes.

(d) Calculation Methodology 4. Calculate the annual CO₂ mass emissions from all fuels combusted in a unit, by using data from continuous emission monitoring systems (CEMS) as specified in (d)(1) through (d)(7).

(1) For the person that combusts fossil fuels or biomass fuels and operates a CO₂ CEMS and stack gas flow rate monitor that is required by any federal or provincial regulation., use CO₂ or O₂ concentrations and flue

gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided in Report EPS 1/PG/7. For these facilities:

- (A) The person shall report CO₂ emissions for the reporting year in tonnes based on the sum of hourly CO₂ mass emissions over the year,.
 - (B) If the person that combusts biomass fuels uses O₂ concentrations to calculate CO₂ concentrations, annual source testing must demonstrate that calculated CO₂ concentrations when compared to measured CO₂ concentrations meet the Relative Accuracy Test Audit (RATA) requirements in Environment Canada "Protocols and Performance specifications for Continuous Monitoring of Gaseous Emissions from Thermal Power Generation - Report EPS 1/PG/7.
- (2) For the person that combusts waste-derived fuels, and operates a CO₂ CEMS and stack gas flow rate monitor that is required by any federal or provincial regulation, use CO₂ concentrations and flue gas flow measurements to determine hourly CO₂ mass emissions using methodologies provided in Report EPS 1/PG/7. For these facilities:
- (A) Annual CO₂ emissions shall be reported in tonnes based on the sum of hourly CO₂ mass emissions over the year.
 - (B) Emissions calculations shall not be based on O₂ concentrations.
- (3) The person that combusts waste-derived fuels and calculates CO₂ emissions using the methodology provided in ON.23(d)(2) shall determine the portion of emissions associated with the combustion of biomass using the method provided in ON.23(e).
- (4) A person who uses CEMS data to report CO₂ emissions from a facility that co-fires fossil fuels with biomass fuels or waste-derived fuels that are partly biomass shall determine the portion of total CO₂ emissions separately assigned to the fossil fuel and the biomass using the method provided in ON.23(e), if applicable. The person who co-fires biomass fuels with fossil fuels may elect to calculate CO₂ emissions for the fossil fuels using methods designated in ON.23(a) or ON.23(b)(1), as applicable, by fuel type and then calculate biomass fuel emissions by subtracting the fossil fuel related emissions from the total CO₂ emissions determined using the CEMS based methodology.
- (5) For any units for which CO₂ emissions are reported using CEMS data, the person is relieved of the requirement to separately report process emissions from combustion emissions for that unit and to report emissions separately for different fossil fuels for that unit when only fossil fuels are co-fired. In this circumstance, the person shall still report fuel use by fuel type as otherwise required.

- (6) If a person chooses to add devices to an existing CEMS for the purpose of measuring CO₂ concentrations or flue gas flow, the person shall select and operate the added devices pursuant to the requirements in Report EPS 1/PG/7 that apply to the facility.
- (e) Mixtures of biomass or biomass fuel and fossil fuel.
 - (1) The person that combusts fuels or fuel mixtures for which the biomass fraction is known or can be documented shall use the applicable equations in ON.23(a) through (c) to report the total biomass emissions or determine the biomass fraction by subtracting the fossil fuel fraction from the total emissions.
 - (2) The person that combusts fuels or fuel mixtures for which the biomass fraction is unknown or cannot be documented (for example, municipal solid waste or tire-derived fuels) shall determine the biomass portion of CO₂ emissions using ASTM D6866-06a, as specified in this paragraph. This procedure is not required for fuels that contain less than 5 per cent biomass by weight or for waste-derived fuels that are less than 30 per cent by weight of total fuels combusted in the year for which emissions are being reported, except where the person wishes to report a biomass fuel fraction of CO₂ emissions. In calculating emissions under this section:
 - (A) The person shall conduct ASTM D6866-06a analysis on a representative fuel or exhaust gas sample at least every three months, and shall collect exhaust gas samples over at least 24 consecutive hours following the standard practice specified by ASTM D7459-08.
 - (B) The person shall divide total CO₂ emissions between biomass fuel emissions and non-biomass fuel emissions using the average proportions of the samples analyzed for the year for which emissions are being reported.
 - (C) If there is a common fuel source to multiple units at the facility, the person may elect to conduct ASTM D6866-06a testing for one of the units.

ON.24 Calculation of CH₄ and N₂O Emissions

Calculate the annual CH₄ and N₂O mass emissions from stationary fuel combustion sources using the procedures in paragraph (a), (b), (c), or (d) of ON.24 as appropriate.

Use of the four CH₄ and N₂O emissions calculation methodologies described in paragraphs (a) through (d) of this section is subject to the following requirements and restrictions:

- (1) Calculation Methodology 1 (ON.24(a)) may not be used by a facility that is subject to the verification requirements of the Regulation, except for stationary combustion units that combust natural gas with a higher heating value between 0.0363 and 0.0428 G J/Sm³.
- (2) Calculation methodology 2 and 4 (ON.24(b) and (d)) may be used for a unit of any size combusting any type of fuel.
- (3) Calculation methodology 3 (ON.24(c)) may only be used for biomass or municipal solid waste combustion.

- (a) Calculation Methodology 1: If the heat content of the fuel is not measured for CO₂ estimation, calculate CH₄ and N₂O emissions using Equation 20-8 for all fuels except coal. For coal, use Equation 20-9:

$$E_{CH_4} \text{ or } E_{N_2O} = Fuel \times HHV_D \times EF \times 0.000001 \quad \text{Equation 20-8}$$

$$E_{CH_4} \text{ or } E_{N_2O} = Fuel \times EF_c \times 0.000001 \quad \text{Equation 20-9}$$

Where:

$E_{CH_4} \text{ or } E_{N_2O}$	=	Combustion emissions from specific fuel type, tonnes CH ₄ or N ₂ O per year.
Fuel	=	Mass or volume of fuel combusted per year (express mass in tonnes for solid fuel, volume in Sm ³ for gaseous fuel, and volume in kilolitres for liquid fuel).
HHV _D	=	Default high heat value specified by fuel type provided in Table 20-1, (GJ/tonne for solid fuel, GJ/kilolitre for liquid fuel, or GJ/Sm ³ for gaseous fuel).
EF	=	Default CH ₄ or N ₂ O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH ₄ or N ₂ O per GJ.
EF _c	=	Default CH ₄ or N ₂ O emission factor for coal provided in Table 20-6, grams CH ₄ or N ₂ O per tonnes of coal
0.000001	=	Factor to convert grams to tonnes.

- (b) Calculation Methodology 2: If the heat content of the fuel is measured or provided by the fuel supplier for CO₂ estimation, calculate CH₄ and N₂O emissions using Equation 20-10 for all fuels except coal. For coal, use Equation 20-11:

$$E_{CH_4} \text{ or } E_{N_2O} = \sum_{p=1}^n Fuel_p \times HHV_p \times EF \times 0.000001$$

Equation 20-10

$$E_{CH_4} \text{ or } E_{N_2O} = \sum_{p=1}^n Fuel_p \times EF_c \times 0.000001$$

Equation 20-11

Where:

$E_{CH_4} \text{ or } E_{N_2O}$	=	CH ₄ or N ₂ O emissions from a specific fuel type, tonnes CH ₄ or N ₂ O per year.
$Fuel_p$	=	Mass or volume of the fuel combusted during the measurement period “p” (express mass in tonnes for solid fuel, volume in Sm ³ for gaseous fuel, and volume in kilolitres for liquid fuel).
HHV_p	=	High heat value measured directly or provided by the fuel supplier for the measurement period, p, specified by fuel type (GJ/tonne for solid fuel, GJ per kilolitre for liquid fuel, or GJ/Sm ³ for gaseous fuel).
EF	=	Default CH ₄ or N ₂ O emission factor provided in Tables 20-2 or 20-4, as applicable, grams CH ₄ or N ₂ O per GJ.
EF_c	=	CH ₄ or N ₂ O emission factor for coal, either measured directly or provided by the fuel supplier, grams CH ₄ or N ₂ O per tonnes of coal.
0.000001	=	Factor to convert grams to tonnes.

(c) Calculation Methodology 3: For biomass and municipal solid waste combustion, the person may elect to use Equation 20-12 of this section to estimate CH₄ and N₂O emissions:

$$E_{CH_4} \text{ or } E_{N_2O} = Steam \times B \times EF \times 0.000001$$

Equation 20-12

Where:

$E_{CH_4} \text{ or } E_{N_2O}$	=	Annual CH ₄ or N ₂ O emissions from the combustion of a biomass and municipal solid waste, tonnes/year.
Steam	=	Total mass of steam generated by municipal solid waste biomass and combustion during the reporting year, tonnes steam/year.
B	=	Ratio of the boiler’s design rated heat input capacity to its design rated steam output, GJ/tonne steam.
EF	=	Fuel-specific emission factor for CH ₄ or N ₂ O, from Tables 20-2, 20-4 or 20-6, as applicable, grams CH ₄ or N ₂ O per GJ.

0.000001 = Conversion factor from grams to tonnes.

- (d) Calculation Methodology 4: The person may elect to calculate CH₄ or N₂O emissions using source-specific emission factors derived from source tests conducted at least annually. The person shall submit a pretest plan to the Director in the first year of reporting. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

ON.25 Sampling, Analysis, and Measurement Requirements

- (a) Fuel Sampling Requirements. Fuel sampling must be conducted or fuel sampling results must be received from the fuel supplier at the frequency specified in paragraphs (a)(1) through (a)(5) of this section.
- (1) Once for each new fuel shipment or delivery on a monthly basis for coal and fuel oil
 - (2) Once per quarter for middle distillates (diesel, gasoline, fuel oil, kerosene), residual oil, liquid waste-derived fuels, and LPG (ethane, propane, isobutene, n-butane, unspecified LPG).
 - (3) Semiannually (i.e., twice in a calendar year) for natural gas, associated gas, and mixtures of low heat content gas.
 - (4) Once per quarter for gases derived from biomass including landfill gas and biogas from wastewater treatment or agricultural processes.
 - (5) Monthly for solid fuels, as specified below:
 - (A) The monthly solid fuel sample shall be a composite sample of weekly samples.
 - (B) The solid fuel shall be sampled at a location after all fuel treatment operations but before fuel mixing and the samples shall be representative of the fuel chemical and physical characteristics immediately prior to combustion.
 - (C) Each weekly sub-sample shall be collected at a time (day and hour) of the week when the fuel consumption rate is representative and unbiased.
 - (D) Four weekly samples (or a sample collected during each week of operation during the month) of equal mass shall be combined to form the monthly composite sample.
 - (E) The monthly composite sample shall be homogenized and well mixed prior to withdrawal of a sample for analysis.
 - (F) One in twelve composite samples shall be randomly selected for additional analysis of its discrete constituent samples. This information will be used to monitor the homogeneity of the composite.
 - (6) For biomass fuels and waste-derived fuels, the following may apply in lieu of ON.25(a)(4):

- (A) If CO₂ emissions are calculated using ON.23(c)(1), the source-specific carbon content is determined annually.
- (B) If CO₂ emissions are calculated using ON.23(c)(2) (biomass fuels and municipal solid waste only), the person shall adjust the emission factor, in kg CO₂/GJ not less frequently than every third year, through a stack test measurement of CO₂ and use of the applicable ASME Performance Test Code to determine heat input from all heat outputs, including the steam, flue gases, ash and losses.

(b) Fuel Consumption Monitoring Requirements.

- (1) Facilities may determine fuel consumption on the basis of direct measurement or recorded fuel purchase or sales invoices measuring any stock change (measured in GJ, litres, million Sm³, tonnes or bone dry tonnes) using the following equation:

$$Fuel = Fuel_p - Fuel_s + Fuel_b - Fuel_e \quad \text{Equation 20-13}$$

Where:

- Fuel = Fuel consumption in the report year; GJ, litres, million Sm³, tonnes or bone dry tonnes
- Fuel_p = Total fuel purchased, GJ; litres, million Sm³, tonnes or bone dry tonnes
- Fuel_s = Total Fuel Sales; GJ, litres, million Sm³, tonnes or bone dry tonnes
- Fuel_b = Amount of fuel stored at the beginning of year; GJ, litres, million Sm³, tonnes or bone dry tonnes
- Fuel_e = Amount of fuel stored at year end; GJ, litres, million Sm³, tonnes or bone dry tonnes

- (2) Fuel consumption measured in GJ values shall be converted to the required metrics of mass or volume using heat content values that are either provided by the supplier, measured by the facility, or provided in Table 20-1.
- (3) All oil and gas flow metres (except for gas billing metres) shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using an applicable flow metre test method listed in section 5 of the Guideline or the calibration procedures specified by the flow metre manufacturer. Fuel flow metres shall be recalibrated either annually or at the minimum frequency specified by the manufacturer. For units and processes that operate continuously with infrequent outages, the initial calibration of a flow metre or other devices may be postponed until the next scheduled maintenance shutdown. The person shall prepare a plan documenting any postponements, including the date for the next planned shutdown, and submit it to the Director before December 31, 2010.
- (4) For fuel oil, tank drop measurements may also be used.
- (5) Equipment used to measure solid fuel consumption at a facility shall be calibrated prior to the first year for which GHG emissions are reported under this rule, using a test method listed in section 5 of the Guideline or the calibration procedures

specified by the equipment manufacturer. Equipment shall be recalibrated either annually or at the minimum frequency specified by the manufacturer

- (c) Fuel Heat Content Monitoring Requirements. High heat values shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the person, in either case using an applicable analytical method listed in section 5 of the Guideline.

For gases, use ASTM D1826-94, ASTM D3588-98, ASTM D4891-89, GPA Standard 2261-00. The person may alternatively elect to use on-line instrumentation that determines heating value accurate to within ± 5.0 percent. Where existing on-line instrumentation provides only low heat value, the person shall convert the value to high heat value as follows:

$$HHV = LHV \times CF$$

Equation 20-14

Where:

HHV = fuel or fuel mixture high heat value, GJ/ Sm³.

LHV = fuel or fuel mixture low heat value, GJ/ Sm³.

CF = conversion factor.

For natural gas, a CF of 1.10 shall be used. For refinery fuel gas and mixtures of refinery fuel gas, a weekly average fuel system-specific CF shall be derived as follows:

- (A) by concurrent LHV instrumentation measurements and HHV determined by on-line instrumentation or laboratory analysis as part of the daily carbon content determination; or,
- (B) by the HHV/LHV ratio obtained from the laboratory analysis of the daily samples.

- (6) For middle distillates and oil, or liquid waste-derived fuels, use ASTM D240-02, or ASTM D4809-06.
- (7) For solid biomass-derived fuels, use ASTM D5865-07a.
- (8) For waste-derived fuels, use ASTM D5865-07a or ASTM D5468-02. The person who combusts waste-derived fuels that are not pure biomass fuels shall determine the biomass fuel portion of CO₂ emissions using the method specified in section ON.23(e), if applicable.
- (d) Fuel Carbon Content Monitoring Requirements. Fuel carbon content and molecular weight, or molar fraction for gaseous fuels shall be based on the results of fuel sampling and analysis received from the fuel supplier or determined by the person, in either case using an applicable analytical method listed in section 5 of the Guideline.
 - (1) For coal and coke, solid biomass fuels, and waste-derived fuels; use ASTM 5373-08.

- (2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 or computations based on ASTM D3238-95 and either ASTM D2502-04 or ASTM D2503-92.
 - (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90. The person may alternatively elect to use on-line instrumentation that determines fuel carbon content accurate to ± 5 percent.
- (e) Fuel Analytical Data Capture. When the applicable standard quantification methods in Section 4 of the Guideline require periodic collection of fuel analytical data for an emissions source, the person shall demonstrate every reasonable effort to obtain a fuel analytical data capture rate of 100 per cent for each report year.
- (1) If the person is unable to obtain fuel analytical data such that more than 20 per cent of emissions from a source cannot be directly accounted for, the emissions from that source shall be considered unverifiable for the report year.
 - (2) If the fuel analytical data capture rate is at least 80 per cent but less than 100 per cent for any emissions source identified in methods ON.20 through ON.500, the person shall use the mean of the fuel analytical data results captured to substitute for the missing values for the period of missing data.
- (f) Procedure for Interim Fuel and Other Analytical Data Collection
- (1) In the event of an unforeseen breakdown of fuel analytical data monitoring equipment required for the emissions standard quantification methods in section 4 of the Guidelines, the Director may authorize a person to use an interim data collection procedure if the Director determines that the person has satisfactorily demonstrated that:
 - (A) The breakdown may result in a loss of more than 20 per cent of the source's fuel data for the reporting year, such that emissions for the affected source could not be verified under the provisions of the Regulation;
 - (B) The fuel analytical data monitoring equipment cannot be promptly repaired or replaced without shutting down a process unit significantly affecting facility operations, or that the monitoring equipment must be replaced and replacement equipment is not immediately available;
 - (C) The interim procedure will not remain in effect longer than is reasonably necessary for repair or replacement of the malfunctioning data monitoring equipment; and
 - (D) The request was submitted within 30 calendar days of the breakdown of the fuel analytical data monitoring equipment.
 - (2) A person seeking approval of an interim data collection procedure must, within 30 days of the monitoring equipment breakdown, submit a written request to the Director that includes all of the following:
 - (A) The proposed start date and end date of the interim procedure;
 - (B) A detailed description of what data are affected by the breakdown;
 - (C) A discussion of the accuracy of data collected during the interim procedure compared with the data collected under the person's usual equipment-based method;

- (D) A demonstration that no feasible alternative procedure exists that would provide more accurate emissions data; and
- (E) A demonstration that the proposed interim procedure meets the criteria specified in section ON.25(f)(1).
- (3) The Director may limit the duration of the interim data collection procedure or include other conditions of approval to ensure the criteria in section ON.25(f)(1) are met.
- (4) When approving an interim data collection procedure, the Director shall determine whether the accuracy of data collected under the procedure is reasonably equivalent to data collected from properly functioning monitoring equipment, and if it is not, the relative accuracy to assign for purposes of assessing possible material misstatement under the Regulation.

Table 20-1: Default Carbon Content and High Heat Value by Fuel Type

Liquid Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/KL)
Asphalt & Road Oil	19.8	44.46
Aviation Gasoline	19.25	33.52
Diesel	19.06	38.3
Aviation Turbo Fuel	18.67	37.4
Kerosene	18.53	37.68
Propane	16.35	25.31
Ethane	15.61	17.22
Butane	16.67	28.44
Lubricants	19.66	39.16
Motor Gasoline - Off-Road	18.02	35
Light Fuel Oil	19.35	38.8
Residual Fuel Oil (#5 & 6)	20.07	42.5
Crude Oil	19.8	38.32
Naphtha	19.33	35.17
Petrochemical Feedstocks	19.33	35.17
Petroleum Coke - Refinery Use	22.71	46.35
Petroleum Coke - Upgrader Use	22.71	40.57
Solid Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/metric tonne)
Anthracite Coal	23.74	27.7
Bituminous Coal	20.97	26.33
Foreign Bituminous Coal	21.79	29.82
Sub-Bituminous Coal	25.05	19.15
Lignite	29.97	15
Coal Coke	23.69	28.83
Solid Wood Waste	28.41	18
Spent Puling Liquor	N/A	14
Gaseous Fuels	Carbon Content (kg C /GJ)	High Heat Value (GJ/m3)

Natural Gas	14.12	0.03832
Coke Oven Gas	23.03	0.01914
Landfill Gas	14.97	0.0359

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007; and Statistics Canada Report on Energy Supply and Demand in Canada

Table 20-2: Default Emission Factors by Fuel Type

	CO₂ Emission Factor (kg /L)	CO₂ Emission Factor (kg /GJ)	CH₄ Emission Factor (g/L)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/L)	N₂O Emission Factor (g/GJ)
Liquid Fuels						
Aviation Gasoline	2.342	69.87	2.2	65.63	0.23	6.862
Diesel	2.663	69.53	0.133	3.473	0.4	10.44
Aviation Turbo Fuel	2.534	67.75	0.08	2.139	0.23	6.150
Kerosene						
- Electric Utilities	2.534	67.25	0.006	0.159	0.031	0.823
- Industrial	2.534	67.25	0.006	0.159	0.031	0.823
- Producer Consumption	2.534	67.25	0.006	0.159	0.031	0.823
- Forestry, Construction, and Commercial/ Institutional	2.534	67.25	0.026	0.69	0.031	0.823
Propane						
- Residential	1.51	59.66	0.027	1.067	0.108	4.267
- All other uses	1.51	59.66	0.024	0.948	0.108	4.267
Ethane	0.976	56.68	N/A	N/A	N/A	N/A
Butane	1.73	60.83	0.024	0.844	0.108	3.797
Lubricants	1.41	36.01	N/A	N/A	N/A	N/A
Motor Gasoline - Off-Road	2.289	65.40	2.7	77.14	0.05	1.429
Light Fuel Oil						
- Electric Utilities	2.725	70.23	0.18	4.639	0.031	0.799
- Industrial	2.725	70.23	0.006	0.155	0.031	0.799
- Producer Consumption	2.643	68.12	0.006	0.155	0.031	0.799
- Forestry, Construction, and Commercial/ Institutional	2.725	70.23	0.026	0.67	0.031	0.799
Residual Fuel Oil (#5 & 6)						
- Electric Utilities	3.124	73.51	0.034	0.800	0.064	1.506
- Industrial	3.124	73.51	0.12	2.824	0.064	1.506
- Producer Consumption	3.158	74.31	0.12	2.824	0.064	1.506

- Forestry, Construction, and Commercial/ Institutional	3.124	73.51	0.057	1.341	0.064	1.820
Naphtha	0.625	17.77	N/A	N/A	N/A	N/A
Petrochemical Feedstocks	0.5	14.22	N/A	N/A	N/A	N/A
Petroleum Coke - Refinery Use	3.826	82.55	0.12	2.589	0.0265	0.572
Petroleum Coke - Upgrader Use	3.494	86.12	0.12	2.958	0.0231	0.569
Biomass and Other Solid Fuels	CO₂ Emission Factor (kg /kg)	CO₂ Emission Factor (kg /GJ)	CH₄ Emission Factor (g/kg)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/kg)	N₂O Emission Factor (g/GJ)
Landfill Gas	29.89	833	0.6	16.7	0.06	1.671
Wood Waste (Env. Canada) ¹	0.95	52.8	0.05	2.778	0.02	1.111
Wood Waste (U.S. EPA) ²	1.590	88.9	0.51	28.4	0.068	3.79
Spent Pulp Liquor (Env.Canada)	1.428	102.0	0.05	3.571	0.02	1.429
Spent Pulp Liquor (U.S. EPA)	1.394	99.60	0.44	31.65	0.073	5.275
Coal Coke	2.48	86.02	0.03	1.041	0.02	0.694
Tires	N/A	85	N/A	N/A	N/A	N/A
Gaseous Fuels	CO₂ Emission Factor (kg /m3)	CO₂ Emission Factor (kg /GJ)	CH₄ Emission Factor (g/m3)	CH₄ Emission Factor (g/GJ)	N₂O Emission Factor (g/m3)	N₂O Emission Factor (g/GJ)
Coke Oven Gas	1.6	83.60	0.037	1.933	0.035	1.829

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007,
unless otherwise stated

¹ Assumes 50% moisture content of wood waste

² Assumes 12% moisture content of wood waste

Table 20-3: Default Carbon Dioxide Emission Factors for Natural Gas by Province

	Marketable Gas (kg/m3)	Marketable Gas (kg/GJ)	Non-Marketable Gas (kg/m3)	Non-Marketable Gas (kg/GJ)
Quebec	1.878	49.01	Not occurring	Not occurring
Ontario	1.879	49.03	Not occurring	Not occurring
Manitoba	1.877	48.98	Not occurring	Not occurring
British Columbia	1.916	50.00	2.151	56.13

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-4: Default Methane and Nitrous Oxide Emission Factors for Natural Gas

	CH₄ (g/m³)	CH₄ (g/GJ)	N₂O (g/m³)	N₂O (g/GJ)
Electric Utilities	0.49	12.79	0.049	1.279
Industrial	0.037	0.966	0.033	0.861
Producer Consumption (Non- marketable)	6.5	169.6	0.06	1.566
Pipelines	1.9	49.58	0.05	1.305
Cement	0.037	0.966	0.034	0.887
Manufacturing Industries	0.037	0.966	0.033	0.861
Residential, Construction, Commercial/ Institutional, Agriculture	0.037	0.966	0.035	0.913

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-5: Default Carbon Dioxide Emission Factors for Coal

	Emission Factor (kg/kg)	Emission Factor (kg/GJ)
Quebec		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.34	88.9
- Anthracite	2.39	86.3
Ontario		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.48	98.7
- Anthracite	2.39	86.3
Manitoba		
- Canadian Bituminous	2.25	85.5
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.73	90.3
- Lignite	1.42	94.7
- Anthracite	2.39	86.3
British Columbia		
- Canadian Bituminous	2.07	78.6
- U.S. Bituminous	2.43	81.5
- Sub-bituminous	1.77	92.4

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-6: Default Methane and Nitrous Oxide Emission Factors for Coal

	CH ₄ Emission Factor (kg/Mg)	N ₂ O Emission Factor (kg/Mg)
Electric Utilities	0.022	0.032
Industry and Heat and Steam Plants	0.03	0.02
Residential, Public Administration	4	0.02

Source: Environment Canada National Inventory Report on Greenhouse Gases and Sinks, 1990-2007

Table 20-7: Other Emission Factors

	CO ₂ Emission Factor (kg/GJ)	CH ₄ Emission Factor (g/GJ)	N ₂ O Emission Factor (g/GJ)
Municipal Solid Waste	91.7	30	4
Peat	103	1	1.5

Source: 2006 IPCC Guidelines for National Greenhouse Gas Inventories, unless otherwise stated.

Appendix 11 Glass Production

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart N, sections 98.140, 98.143 – 98.146.

Appendix 12 HCFC-22 Production

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart O sections 98.150, 98.153 – 98.156.

Appendix 13 ON.130 Hydrogen Production

ON.131 Source Category Definition

A hydrogen production process produces hydrogen gas by steam hydrocarbon reforming, partial oxidation of hydrocarbons, or other transformation of hydrocarbon feedstock. The hydrogen produced may be either transferred offsite or used onsite at petrochemical, ammonia production, refineries, and other plants.

ON.132 Greenhouse Gas Reporting Requirements

For the purpose of Section 6 of the Regulation the annual emissions data report for hydrogen production shall include the following information at the facility level calculated in accordance this method:

- a) Process CO₂ Emissions. The CO₂ process emissions from the hydrogen production process as specified in ON.133.
- b) Feedstock Consumption (if estimating emissions using mass balance approach in ON.133(b)). Annual feedstock consumption by feedstock type (including petroleum coke) reported in units of million standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.
- c) Production. Annual hydrogen produced in standard cubic metres.
- d) CO₂, N₂O, and CH₄ emissions from stationary combustion units not covered by this method shall follow the calculation methods and reporting requirements in ON.20.

ON.133 Calculation of Greenhouse Gas Emissions

The person shall calculate and report CO₂ process emissions using the methods in paragraphs (a) or (b) of this section.

- a) Continuous Emission Monitoring Systems. The person may calculate CO₂ process emissions using CEMS. The person must comply with the requirements in section ON.20.
- b) Feedstock Mass Balance. The person may calculate CO₂ process emissions using the following method. The factor S shall be used only for CO₂ and/or CH₄ emissions that are calculated and reported using applicable methods specified in this Guideline. For example, carbon species in unconverted feedstock contained in PSA off-gas and hydrogen plant product that is diverted to fuel gas systems, fed to downstream units, or diverted to flare may be included in the factor S provided the CO₂ and/or CH₄ emissions are reported using other methods in this Guideline.

$$E_{CO_2} = \sum_{i=1}^n \sum_{j=1}^y [(FS_j * CF_j) - S_j] * 3.664 * 0.001 \quad \text{Equation 130-1}$$

Where:

E_{CO_2}	=	CO ₂ emitted from feedstock, tonnes/year
n	=	Number of operating days per year.
FS_j	=	Feedstock j consumption rate, Sm ³ /day
CF_j	=	Carbon content of feedstock j, kg C/ Sm ³ feedstock
y	=	Total number of feedstocks
S_j	=	Carbon accounted for elsewhere, kg C/day
3.664	=	ratio of molecular weights, carbon dioxide to carbon
0.001	=	conversion factor from kilograms to tonnes

ON.134 Sampling, Analysis, and Measurement Requirements

- a) The person using CEMS to estimate CO₂ emissions shall comply with the monitoring requirements in section ON.20.
- b) The person using the method in section ON.133 (b) shall perform the following monitoring:
 - (1) measure the feedstock consumption rate daily.
 - (2) collect samples of each feedstock consumed and analyze each sample for carbon content using the methods specified in ON.25(d). For natural gas feedstock not mixed with another feedstock prior to consumption, samples shall be collected and analyzed once per month. For all other feedstocks, samples shall be collected and analyzed daily. The samples shall be collected from a location in the feedstock handling system that provides samples representative of the feedstock consumed in the hydrogen production process.
 - (3) measure the hydrogen produced daily.
 - (4) measure the CO₂ and CO collected daily.

Appendix 14 ON.150 Iron and Steel Manufacturing

ON.151 Source Category Definition

Iron and steel manufacturing comprises four categories:

1. primary facilities that produce both iron and steel,
2. secondary steelmaking facilities,
3. iron production facilities, and
4. offsite production of metallurgical coke.

These processes may occur together in an “integrated” facility or they may occur in separate facilities. This category includes both integrated and separate facilities.

ON.152 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for iron and steel manufacturing shall include the following information at the facility level calculated in accordance this method:

- a) Annual total emissions of CO₂ and CH₄ at the facility level expressed in tonnes.
- b) CO₂ and CH₄ emissions from coke production tonnes/year
- c) The following information from coke production:
 - (1) Quantity of coking coal consumed in coke production, tonnes/year
 - (2) Quantity of other process materials (e.g., natural gas, fuel oil, etc.) consumed in coke production, tonnes/year
- d) CO₂ and CH₄ emissions from iron and steel production, tonnes/year
- e) the following information from iron and steel production:
 - (1) Quantity of coke consumed in iron and steel production (excluding sinter production), tonnes/year
 - (2) Quantity of on-site coke oven by-products (e.g., coal tar, light oil, coke breeze, etc.) consumed in blast furnace, tonnes/year
 - (3) Quantity of steel produced, tonnes/year
 - (4) Quantity of iron production not converted to steel, tonnes/year
- f) Process CO₂ and CH₄ emissions from sinter production (tonnes/year) and the following information:
 - (1) Quantity of sinter produced, tonnes/year
- g) Process CO₂ and CH₄ emissions from direct reduced iron production (tonnes) and the following information:

- (1) Quantity of direct reduced iron produced, tonnes/year
- h) Annual CO₂, N₂O, and CH₄ emissions from stationary combustion units not covered by this method shall follow the calculation methods and reporting requirements in ON.20.

ON.153 Calculation of CO₂ Emissions

- a) Process CO₂ emissions. Determine process CO₂ emissions as specified under either paragraph (1) or (2) of this section.

(1) Continuous emissions monitoring systems (CEMS) as specified in ON.23(d).

(2) Calculation methodologies specified in paragraph (b) of this section.

Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions using the following mass balance approach:

- b) Calculate the coke production CO₂ (either within integrated facilities or at offsite facilities) emissions using Equation 150-1 (if applicable):

$$E_{CO_2\text{coke}} = \left[(CC \times C_{CC}) + \sum_a (PM_a \times C_a) + (BG \times C_{BG}) - (CO \times C_{CO}) - (COG \times C_{COG}) - \sum_b (COB_b \times C_b) \right] \times 3.664$$

Equation 150-1

Where:

$E_{CO_2\text{coke}}$	=	Emissions of CO ₂ from coke production, tonnes/year
CC	=	Quantity of coking coal, tonnes/year
PM_a	=	Quantity of other process material a (not included as separate terms), such as natural gas or fuel oil, tonnes/year
BG	=	Quantity of blast furnace gas consumed in coke ovens, tonnes/year
CO	=	Quantity of coke produced, tonnes/year
COG	=	Quantity of coke oven gas transferred out of the coke oven, tonnes/year
COB_b	=	Quantity of coke oven by-product b recovered, tonnes/year
C_x	=	Carbon content of material input or output x, tonnes C/tonne of x
3.664	=	ratio of molecular weight, carbon dioxide to carbon

- c) Calculate the iron and steel production CO₂ emissions using Equation 150-2:

$$E_{CO_2\text{iron, steel}} = \left[(CO \times C_{CO}) + \sum_a (COB_a \times C_a) + (CI \times C_{CI}) + (L \times C_L) + (D \times C_D) + (CE \times C_{CE}) + (DRI \times C_{DRI}) \right]$$

$$+ \sum_b (O_b \times C_b) + (COG \times C_{COG}) - (S \times C_S) - (IP \times C_{IP}) - (BG \times C_{BG}) \Big] \times 3.664$$

Equation 150-2

Where:

$E_{CO2iron,steel}$	=	Emissions of CO ₂ from iron and steel production, tonnes/year
CO	=	Quantity of coke consumed (excluding sinter production), tonnes/year
COB _a	=	Quantity of coke oven by-product a consumed in blast furnace, tonnes/year
CI	=	Quantity of coal directly injected into blast furnace, tonnes/year
L	=	Quantity of limestone consumed, tonnes/year
D	=	Quantity of dolomite consumed, tonnes/year
CE	=	Quantity of carbon electrodes consumed in EAFs, tonnes/year
DRI	=	Quantity of direct reduced iron introduced to an EAF or BOF, tonnes/year
O _b	=	Quantity of other carbonaceous and process material b, such as sinter or waste plastic, tonnes/year
COG	=	Quantity of coke oven gas consumed in blast furnace, tonnes/year
S	=	Quantity of steel produced, tonnes/year
IP	=	Quantity of iron production not converted to steel, tonnes/year
BG	=	Quantity of blast furnace gas transferred out of the blast furnace, tonnes/year
C _x	=	Carbon content of material input or output x (tonnes C/tonne of x);
3.664	=	ratio of molecular weight, carbon dioxide to carbon

- d) Calculate the sinter production CO₂ emissions using Equation 150-3 (if applicable):

$$E_{CO_2 \text{ sinter}} = \left[(CBR \times C_{CBR}) + (COG \times C_{COG}) + (BG \times C_{BG}) + \sum_a (PM_a \times C_a) - (SOG \times C_{SOG}) \right] \times 3.664$$

Equation 150-3

Where:

$E_{CO_2 \text{ sinter}}$	=	Emissions of CO ₂ from sinter production, tonnes/year
CBR	=	Quantity of purchased and onsite produced coke breeze used for sinter production, tonnes/year
COG	=	Quantity of coke oven gas consumed for sinter production, tonnes/year
BG	=	Quantity of blast furnace gas consumed for sinter production, tonnes/year
PM_a	=	Quantity of other process material a consumed for sinter production (not included as separate terms), such as natural gas or fuel oil, tonnes/year
SOG	=	Quantity of sinter off gas transferred out of the plant, tonnes/year
C_x	=	Carbon content of material input or output x (tonnes C/tonne of x);
3.664	=	ratio of molecular weight, carbon dioxide to carbon

- e) Calculate the direct reduced iron production CO₂ emissions using Equation 150-4 (if applicable):

$$E_{CO_2 \text{ DRI}} = [(DRI_{NG} \times C_{NG}) + (DRI_{BZ} \times C_{BZ}) + (DRI_{CK} \times C_{CK}) - (DRI \times C_{DRI})] \times 3.664$$

Equation 150-4

Where:

$E_{CO_2 \text{ DRI}}$	=	Emissions of CO ₂ from direct reduced iron production, tonnes/year
DRI_{NG}	=	Energy from natural gas used in direct reduced iron production, GJ/year
DRI_{BZ}	=	Energy from coke breeze used in direct reduced iron production, GJ/year
DRI_{CK}	=	Energy from metallurgical coke used in direct reduced iron production, GJ/year
DRI	=	Quantity of direct reduced iron produced, tonnes/year
C_{NG}	=	Carbon content of natural gas, tonne C/GJ

C_{BZ}	=	Carbon content of coke breeze, tonne C/GJ
C_{CK}	=	Carbon content of metallurgical coke, tonne C/GJ
C_{DRI}	=	Carbon content of direct reduced iron produced, tonnes of C/tonne of direct reduced iron
3.664	=	ratio of molecular weight, carbon dioxide to carbon

f) Calculate the total CO₂ emissions using Equation 150-5:

$$E_{CO_2} = E_{CO_{2coke}} + E_{CO_{2iron,steel}} + E_{CO_{2sinter}} + E_{CO_{2DRI}} \quad \text{Equation 150-5}$$

Where:

E_{CO_2}	=	Total CO ₂ emissions, tonnes/year
$E_{CO_2 coke}$	=	Emissions from coke production, tonnes/year
$E_{CO_2 iron,steel}$	=	Emissions from iron and steel production, tonnes/year
$E_{CO_2 sinter}$	=	Emissions from sinter production, tonnes/year
$E_{CO_2 DRI}$	=	Emissions from direct reduced iron production, tonnes/year

ON.154 Calculation of CH₄ Emissions

- a) Process CH₄ emissions. Determine process CH₄ emissions as specified under either paragraph (1) or paragraph (2) of this section.
 - (1) Continuous emissions monitoring systems (CEMS) as specified in ON.23(d).
 - (2) Site-specific emission factors.

ON.155 Sampling, Analysis, and Measurement Requirements

Measurements of carbon contents of the material balance input, output, and by-product materials shall be conducted as described below.

- a) Fuel Carbon Content Requirements. Fuel carbon contents should be monitored in the following manner (from ON.25):
 - (1) For coal and coke, solid biomass-derived fuels, and waste-derived fuels; use ASTM 5373-02.
 - (2) For liquid fuels, use the following ASTM methods: For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02 and either ASTM D2502-04 or ASTM D2503-92.
 - (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90.

- b) **By-Product Carbon Content Requirements.** Carbon contents of by-products (e.g., blast furnace gas, coke oven gas, coal tar, light oil, coke breeze, sinter off gas, etc.) from all iron and steel production processes should be monitored in accordance with a method that is approved by the Director.
- c) **Flux Carbon Content Requirements.** Carbon contents of fluxes (i.e., limestone and dolomite) from all iron and steel production processes should be monitored in the following manner:
 - (1) For limestone and dolomite, use ASTM C25-06.
- d) **Electrode Carbon Content Requirements.** Carbon contents of carbon electrodes used in electric arc furnaces (EAFs) should be monitored in the following manner:
 - (1) Vendor specifications of carbon content in EAF carbon electrodes.
- e) **Finished Product Carbon Content Requirements.** Carbon contents of finished products (i.e., steel, iron not converted to steel, and direct reduced iron) from all iron and steel production processes should be monitored in the following manner:
 - (1) For iron and steel, use ASTM E1019-08 or ASTM E351-93.
- f) **Quantity Measurement Requirements.** The quantities of process inputs, outputs, and by-products must be determined using the following methods:
 - (1) For solid process inputs, outputs, and by-products, quantities must be determined by direct weight measurement using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
 - (2) For liquid process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.
 - (3) For gaseous process inputs, outputs, and by-products, quantities must be determined by direct volume measurement using the same plant instruments used for accounting purposes.

Appendix 15 ON.160 Lead Production

ON.161 Source Category Definition

The lead production category includes two primary production processes used to produce lead from lead concentrates namely the sintering/smelting process and the direct smelting process. This category also includes secondary production or recycling of lead (e.g. primarily from scrapped lead acid batteries).

ON.162 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for lead production shall include the following information at the facility level calculated in accordance this method:

- Annual emissions of CO₂, N₂O, CH₄ at the facility level expressed in tonnes.
- Annual process emissions of CO₂ at the facility level expressed in tonnes.
- Annual quantities of each reducing agent used expressed in tonnes.
- Carbon content of each reducing agent used, tonne C/tonne reducing agent.
- Annual CO₂, N₂O, and CH₄ emissions from stationary combustion units as specified in ON.20 expressed in tonne/year.

ON.163 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- Use a CEMS that complies with the provisions in Report EPS 1/PG/7.
- Calculate total CO₂ emissions using Equation 160-1.

$$E_{CO_2} = \sum_x (RA_x \times C_x) \times 3.664$$

Equation 160-1

Where:

- | | | |
|------------------|---|--|
| ECO ₂ | = | Annual CO ₂ emissions from lead production, tonne/year; |
| RA _x | = | Annual quantity of reducing agent x used, tonne/year; |
| C _x | = | Carbon content of reducing agent x, tonne C/tonne x; |
| 3.664 | = | Ratio of molecular weights of carbon dioxide to carbon. |

ON.164 Sampling, Analysis, and Measurement Requirements

Reducing agent carbon content shall be determined as specified under paragraph (a) or (b) of this section as required in ON.163(b).

- a) Carbon contents from reducing agents should be determined in the following manner:
 - (1) For coal and coke, use ASTM D5373-02.
 - (2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02, ultimate analysis of oil or computations based on ASTM D3238-95 and either ASTM D2502-04 or ASTM D2503-92.
 - (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90.
- b) Carbon contents from reducing agents should be obtained from material vendor or supplier

Appendix 16 ON.170 Lime Manufacturing

ON.171 Source Category Definition

Lime manufacturing is comprised of all processes that are used to manufacture quicklime. Quicklime is defined as calcium oxide or calcium-magnesium oxide. Quicklime is produced via the calcination of limestone or other highly calcareous materials such as dolomite, aragonite, chalk, coral, marble, and shell.

ON.172 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for lime manufacturing shall include the following information at the facility level calculated in accordance this method:

- a) Total emissions of CO₂, CH₄, and N₂O expressed in tonnes.
- b) Annual CO₂ process emissions from quicklime production in tonnes and the following information:
 - (1) For lime production:
 - (A) The emission factor for each type of quicklime for each month, kg CO₂/tonne quicklime.
 - (B) The quantity of each type of quicklime produced for each month, tonne quicklime/month.
 - (2) For the production of calcined byproducts and wastes:
 - (A) The emission factor for each type of calcined byproduct and waste for each quarter, expressed in kg CO₂/tonne of byproduct and waste.
 - (B) The quantity of each type of calcined byproduct/waste produced for each quarter, tonne of byproduct and waste/month.
- c) Annual CO₂, CH₄, and N₂O emissions from fuel combustion in all kilns combined, following the calculation methods and reporting requirements specified in ON.173(c) in tonnes.
- d) Annual CO₂, CH₄, and N₂O emissions from all other fuel combustion units combined (kilns excluded), following the calculation methods and reporting requirements specified in ON.20 in tonnes.
- e) If a CEMS is used to measure CO₂ emissions from kilns, then the requirements of paragraphs (b) and (c) of this section do not apply for CO₂.
- f) The person responsible for lime plants shall also comply with the reporting requirements for any other applicable source category listed in the Regulation, including but not limited to the following:
 - (1) Coal fuel storage as specified in ON.100.

- (2) Electricity generating as specified in ON.40.
- (3) Cogeneration systems as specified in ON.42(f).

ON.173 Calculation of greenhouse Gas Emissions from Kilns

- a) Determine process CO₂ emissions as specified under either paragraph (a)(1) or (a)(2) of this section.
 - (1) Use a CEMS that complies with the provisions in Report EPS 1/PG/7. or
 - (2) Calculate the sum of CO₂ process emissions from kilns and CO₂ fuel combustion emissions from kilns using the calculation methodologies specified in paragraph (b) and (c) of this section.
- b) Process CO₂ Emissions Calculation Methodology. Calculate total CO₂ process emissions as the sum of emissions from quicklime production, using the method specified in paragraph (b)(1) of this section.
 - (1) CO₂ Process Emissions. Calculate CO₂ emissions from the production of each type of quicklime using Equation 170-1 and the plant-specific CO₂ emission factors for quicklime and calcined byproduct and waste as specified in this section.

$$E_{CO_2} = \sum_i^{12} \sum_j^J (QL_{ij} \times EF_{QL_{ij}}) + \sum_k^4 \sum_n^N (BW_{kn} \times EF_{BW_{kn}}) \quad \text{Equation 170-1}$$

Where:

- E_{CO_2} = Annual process CO₂ emissions, tonne CO₂/year.
- QL_{ij} = Quantity of quicklime type “j” produced in month “i”, tonnes.
- $EF_{QL_{ij}}$ = Emission factor of quicklime type “j” for month “i” computed as specified in paragraph (b)(2) of this section, tonnes CO₂/tonne quicklime.
- BW_{kn} = Quantity of type “n” calcined byproduct and waste, including LKD, scrubber sludge and other calcined wastes, produced in quarter “k”, tonnes.
- $EF_{BW_{kn}}$ = Emission factor of type “n” calcined byproduct and waste for quarter “k”, computed as specified in paragraph (b)(3) of this section, tonnes CO₂/tonne calcined byproduct and waste.
- J = Total number of quicklime types.
- N = Total number of calcined byproduct and waste types.

- (2) Monthly CO₂ Emission Factor for Quicklime. Calculate a plant-specific quicklime emission factor (EFQL) for each type of quicklime and month

based on the measured total CaO and MgO content in quicklime using Equation 170-2.

$$EF_{QL} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092) \quad \text{Equation 170-2}$$

Where:

EF_{BW}	=	Process CO ₂ Emission factor for calcined byproduct and waste, tonnes CO ₂ /tonne calcined byproduct and waste.
f_{CaO}	=	Total CaO content of calcined byproduct and waste , weight fraction.
0.785	=	Ratio of molecular weights of CO ₂ to CaO .
f_{MgO}	=	Total MgO content of calcined byproduct and waste.
1.092	=	Ratio of molecular weights of CO ₂ to MgO.

- (3) Quarterly CO₂ Emission Factor for Calcined Byproduct and Waste. If calcined by product and waste is generated then calculate a plant-specific CO₂ emission factor for calcined byproduct and waste for each quarter using Equation 170-3.

$$EF_{BW} = (f_{CaO} \times 0.785) + (f_{MgO} \times 1.092) \quad \text{Equation 170-3}$$

Where:

EF_{BW}	=	Process CO ₂ Emission factor for calcined byproduct and waste, tonnes CO ₂ /tonne calcined byproduct and waste.
f_{CaO}	=	Total CaO content of calcined byproduct and waste , weight fraction.
0.785	=	Ratio of molecular weights of CO ₂ to CaO .
f_{MgO}	=	Total MgO content of calcined byproduct and waste.
1.092	=	Ratio of molecular weights of CO ₂ to MgO.

- c) Fuel Combustion Emissions in Kilns. Calculate CO₂, CH₄, and N₂O emissions from stationary fuel combustion emissions following the calculation methods specified in ON.20. The person responsible for lime manufacturing plants that primarily combust biomass-derived fuels and combust fossil fuels only during periods of start-up, shut-down, or malfunction may report CO₂ emissions from fossil fuels using the emission factor methodology in ON.23(a). “Pure” means that the biomass-derived fuels account for 97 per cent of the total amount of carbon in the fuels burned.

ON.174 Sampling, Analysis, and Measurement Requirements

Determine the chemical composition (per cent total CaO and per cent total MgO) of each lime type and each calcined byproduct and waste type by laboratory analysis on a monthly basis for each lime type, and a quarterly basis for each calcined byproduct and waste type. This determination must be performed according to ASTM Methods C25, C1301 and C1271. Samples for analysis of the calcium oxide and magnesium oxide content of each lime type and each calcined byproduct and waste type should be collected during the same month or quarter as the production data. At least one sample must be collected monthly for each lime type produced during the month and quarterly for each calcined byproduct and waste type produced during the quarter.

- a) The quantity of each type of lime produced is to be estimated monthly using direct measurements (such as rail and truck scales) of lime sales for each lime type.
- b) The quantity of each type of calcined byproduct and waste is to be estimated quarterly using direct measurements (such as rail and truck scales) or a calcined byproduct and waste generation rate (i.e. calcined byproduct produced as a factor of lime production or stone fed into the kilns).

Appendix 17 Nickel Production

The person shall use the method set out in Appendix 7, Copper and Nickel Production.

Appendix 18 Nitric Acid Manufacturing

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart V, sections 98.220, 98.223 – 98.226.

Appendix 19 ON.300 Petrochemical Manufacturing

ON.301 Source Category Definition

The petrochemical manufacturing source category consists of any facility that manufactures petrochemicals, including acrylonitrile, propylene, ethylene, ethylene dichloride, ethylene oxide, or methanol, from feed stocks derived from petroleum, or petroleum and natural gas liquids.

ON.302 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for petrochemical manufacturing shall include the following information at the facility level calculated in accordance this method:

- Stationary Combustion Units. Report annual CO₂, N₂O, and CH₄ emissions as specified in ON.20.
- Flares and Other Oxidizers. Report annual CO₂, N₂O, and CH₄ emissions as specified in ON.303(a).
- Process Vents. Report annual CO₂, N₂O, and CH₄ emissions as specified in ON.303(b).
- Equipment Leaks. Report annual CH₄ emissions as specified in ON.303(c).
- Feedstock Consumption: Report annual feedstock consumption by type for all feedstocks that result in GHG emissions expressed in standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

ON.303 Calculation of GHG Emissions

- Flares and Other Oxidizers. Calculate GHG emissions from flares and oxidation control devices as follows:

Calculate CO₂, CH₄ and N₂O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in ON.20.

Calculate CO₂ emissions for each gas destroyed in a flare or other oxidation control device using Equation 300-1.

$$E_{CO_2} = \sum_{i=1}^N GV_i \times CC_i \times \rho_i \times 3.664 \times 0.001$$

Equation 300-1

Where:

E_{CO_2} = CO₂ emissions, tonnes /year

N	=	Number of gases destroyed
GV _i	=	Volume of gas i destroyed annually, Sm ³ /year
CC _i	=	Average annual carbon content of gas i, kg C/kg fuel
ρ _i	=	Density of the gas i, kg/ Sm ³
3.664	=	Ratio of molecular weights, carbon dioxide to carbon
0.001	=	Conversion factor from kilogram to tonnes

- b) Process Vents. Except for process emissions calculated pursuant to ON.303(a) or (c), you must calculate process emissions of CO₂, CH₄, and N₂O from process vents using Equation 300-2.

$$E_x = \sum_{i=1}^N VR_i \times F_{x,i} \times \rho_x \times VT_i \times 0.001$$

Equation 300-2

Where:

E _x	=	Emissions of x (where x = CO ₂ , N ₂ O, or CH ₄), tonnes/year
N	=	Number of venting events in a year
VR _i	=	Vent rate for venting event i, Sm ³ /unit time
F _{x,i}	=	Molar fraction of x in vent gas stream during event i
ρ _x	=	Density of the x, kg/ Sm ³
VT _i	=	Time duration of venting event i (same unit of time used for VR _i)
0.001	=	Conversion factor from kilograms to tonnes

- c) Equipment Leaks. Calculate CH₄ emissions for each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems as follows:

Identify and screen each valve, pump seal, connector, flange, open-ended line, and other components in natural gas, fuel gas, and off-gas systems using the monitoring method in ON.304. Components identified as “other” components include instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, metres, and polished rods stuffing boxes.

Use the results of the component screening and the following equations to calculate VOC emissions:

For components where the measured screening value is equal to zero when corrected for background, calculate volatile organic compounds (VOC)

emissions using Equation 300-3 and the appropriate default emission factors from Table 300-1:

$$VOC_{0,i} = CC_i \times Zf_{i0} \times t_i \quad \text{Equation 300-3}$$

Where:

- $VOC_{0,i}$ = Zero component VOC emission for component type i, kg/screening period
- i = Component type (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
- CC_i = Number of type i components where the screening value (SV) is 0
- Zf_{i0} = Default zero factor for component type i from Table 300-1, kg/hour
- t_i = Time lapse since last screening for component type i, hours

For components where the measured screening value, corrected for background, is between 0 and 10,000 ppmv, calculate VOC emissions using Equation 300-4 and the appropriate default factors from Table 300-1:

$$VOC_{LC,i} = \sum_{y=1}^Y (\sigma_i \times SV_y^{\beta_i}) \times t_i \quad \text{Equation 300-4}$$

Where:

- $VOC_{LC,i}$ = VOC emissions from component type i with SV between 0 to 10,000 ppmv, kg/screening period
- i = Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open ended-line)
- Y = Number of type i components where the SV is between 0 to 10,000 ppmv
- σ_i = Correlation equation coefficient for component type i from Table 300-1
- SV_y = Screening value for component y
- β_i = Correlation equation exponent for component type i from Table 300-1
- t_i = Time duration for which the component has been leaking - default value is the time lapse since last screening, hours

For components where the screening value, corrected for background, is greater than or equal to 10,000 ppmv, calculate VOC emissions using Equation 300-5 and the appropriate default factors from Table 300-1:

$$VOC_{P,i} = CC_i \times PF_{iP-10} \times t_i \quad \text{Equation 300-5}$$

Where:

- $VOC_{P,i}$ = VOC emissions from component type i with SV greater than 9,999 ppmv, kg/screening period
- i = Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open-ended line)
- CC_i = Number of type i components with SV greater than 9,999 ppmv.
- PF_{iP-10} = VOC emission factor for component type i pegged over 9,999 ppmv from Table 300-1, kg/hour
- t_i = Time duration for which the component has been leaking - default value is the time lapse since last screening, hours

Calculate CH₄ emissions using Equation 300-6 and either a default factor of 0.6 for CFVOC or a site-specific conversion factor calculated from the composition and methane content of the gas.

$$E_{CH_4,i} = \sum_{y=1}^Y (VOC_{0,i} + VOC_{LC,i} + VOC_{P,i})_y \times CF_{VOC} \times 0.001 \quad \text{Equation 300-6}$$

Where:

- $E_{CH_4,i}$ = CH₄ emissions for component type i, tonnes/year
- i = Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open-ended line)
- Y = Number of screenings per year for component type i
- $VOC_{0,i}$ = Zero component VOC emissions for component type i, kg/screening period
- $VOC_{LC,i}$ = VOC emissions for component type i with SV between 0 to 10,000 ppmv, kg/screening period
- $VOC_{P,i}$ = VOC emissions for component type i with SV greater than 9,999 ppmv, kg/screening period
- CF_{VOC} = Conversion factor from volatile organic compounds to methane (default $CF_{VOC} = 0.6$).
- 0.001 = Conversion factor from kilograms to tonnes

ON.304 Sampling, Analysis, and Measurement Requirements

- a) Flares and Other Oxidizers. The person shall measure:
 - (1) The volume of each gas destroyed annually determined to an accuracy of ± 5 percent.
 - (2) The carbon content and molecular weight of each gas quarterly using the methods specified in ON.25 and calculate the annual average values for carbon content and molecular weight for each gas destroyed.
- b) Process Vents. The person shall measure the following parameters for each process vent:
 - (1) The gas flow rate for each venting event.
 - (2) The molar fraction of CO₂, N₂O, and CH₄ in the vent gas stream during each venting event.
 - (3) The duration of each venting event.
- c) Equipment Leaks. The person shall screen each valve, pump seal, connector, flange, and open-ended line used in natural gas, fuel gas, and off-gas systems using the methods specified in CCME EPC-73: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993). Screenings must be performed at the frequency interval required by the Code of Practice.
- d) Feedstock Consumption. The person shall measure the feedstock consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.

Table 300-1. Fugitive Emissions from Gas Service Components

Component Type / Service Type	Default Zero Factor (kg/hour) (SV = 0) Zf_{i0}	Correlation Equation (kg/hour) (SV > 0 and < 10,000) σ_i and β_i	Pegged Factor (kg/hour) (SV > 9,999) PF_{IP-10}
1, Valves	7.8×10^{-6}	$2.27 \times 10^{-6}(SV)^{0.747}$	0.064
2, Pump seals	1.9×10^{-5}	$5.07 \times 10^{-5}(SV)^{0.622}$	0.089
3, Others ^a	4.0×10^{-6}	$8.69 \times 10^{-6}(SV)^{0.642}$	0.082
4, Connectors	7.5×10^{-6}	$1.53 \times 10^{-6}(SV)^{0.736}$	0.030
5, Flanges	3.1×10^{-7}	$4.53 \times 10^{-6}(SV)^{0.706}$	0.095
6, Open-ended lines	2.0×10^{-6}	$1.90 \times 10^{-6}(SV)^{0.724}$	0.033

^a The “other” component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The “other” component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, metres, and polished rods stuffing boxes.

Appendix 20 ON.200 Petroleum Refineries

ON.201 Source Category Definition

A petroleum refinery consists of all processes used to produce gasoline, aromatics, kerosene, distillate fuel oils, residual fuel oils, lubricants, asphalt, or other products through distillation of petroleum or through redistillation, cracking, rearrangement or reforming of unfinished petroleum derivatives.

ON.202 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for petroleum refineries include the following information at the facility level calculated in accordance this method:

- a) Catalyst Regeneration. Report annual CO₂ emissions.
- b) Process Vents. Report annual CO₂, N₂O, and CH₄ emissions.
- c) Asphalt Production. Report annual CO₂ and CH₄ emissions.
- d) Sulfur Recovery. Report annual CO₂ emissions.
- e) Stationary Combustion Units Other than Flares and Control Devices. Report annual CO₂, N₂O, and CH₄ emissions as specified in ON.20.
- f) Flares and Other Control Devices. Report annual CO₂, N₂O, and CH₄ emissions.
- g) Above-Ground Storage Tanks. Report annual CH₄ emissions.
- h) Wastewater Treatment. Report annual CH₄ and N₂O emissions.
- i) Oil-Water Separators. Report annual CH₄ emissions.
- j) Equipment Leaks. Report annual CH₄ emissions.
- k) Feedstock Consumption: Report annual feedstock consumption by type for all feedstocks which result in GHG emissions in the reporting year (including petroleum coke) in units of standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.
- l) Fuel Consumption: Report annual fuel consumption by fuel type consumed in the reporting year in units of standard cubic metres for gases, kilolitres for liquids, tonnes for non-biomass solids, and bone dry tonnes for biomass-derived solid fuels.

ON.203 Calculation of Greenhouse Gas Emissions

The person shall calculate GHG emissions using the methods in paragraphs (a) through (i) of this section.

- a) Catalyst Regeneration. For units equipped with CEMS, the person shall calculate CO₂ process emissions resulting from catalyst regeneration using CEMS in accordance with Report EPS 1/PG/7. In the absence of CEMS data, the person shall use the methods in paragraphs (a)(1) through (a)(3).
- (1) The person shall calculate process CO₂ emissions from the continuous regeneration of catalyst material in fluid catalytic cracking units (FCCU) and fluid cokers using Equations 200-1, 200-2, and 200-3.

$$E_{CO_2} = \sum_{d=1}^Y CR_d \times CF \times 3.664 \times 0.001 \quad \text{Equation 200-1}$$

Where:

E_{CO_2}	=	CO ₂ emissions, tonnes/year
Y	=	Number of operating days in the year
CR_d	=	Daily average coke burn rate, calculated from equation 200-2, kg/day
CF	=	Carbon fraction in coke burned
3.664	=	Ratio of molecular weights, carbon dioxide to carbon
0.001	=	Conversion factor from kilograms to tonnes

$$CR_d = \left[\sum_{i=1}^H [K_1 Q_r \times (\%CO_2 + \%CO) + K_2 Q_a - K_3 Q_r \times (\%CO / 2 + \%CO_2 + \%O_2) + K_3 Q_{oxy} \times \%O_{oxy}]_i \right] / H$$

Equation 200-2

Where:

CR_d	=	Daily average coke burn rate, kg/day
H	=	Number of operating hours per day
K_1, K_2, K_3	=	Material balance and conversion factors (from Table 200-1)
Q_r	=	Volumetric flow rate of exhaust gas before entering the emission control system, calculated from equation 200-3, D Sm ³ /min
Q_a	=	Volumetric flow rate of air to regenerator as determined from control room instrumentation, D Sm ³ /min
% CO ₂	=	CO ₂ concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis
%O ₂	=	O ₂ concentration in regenerator exhaust, percent by volume – dry basis

Q_{oxy}	=	Volumetric flow rate of O ₂ enriched air to regenerator as determined from control room instrumentation, D Sm ³ /min
%O _{xy}	=	O ₂ concentration in O ₂ enriched air stream inlet to regenerator, percent by volume – dry basis

$$Q_r = (79 \times Q_a + (100 - \% Q_{xy}) \times Q_{oxy}) / (100 - \% CO_2 - \% CO - \% O_2)$$

Equation 200-3

Where:

Q_r	=	Volumetric flow rate of exhaust gas from regenerator before entering the emission control system, D Sm ³ /min
Q_a	=	Volumetric flow rate of air to regenerator, as determined from control room instrumentation, DSm ³ /min
%Q _{xy}	=	Oxygen concentration in oxygen enriched air stream, percent by volume – dry basis
Q_{oxy}	=	Volumetric flow rate of O ₂ enriched air to regenerator as determined from catalytic cracking unit control room instrumentation, DSm ³ /min
% CO ₂	=	Carbon dioxide concentration in regenerator exhaust, percent by volume – dry basis
%CO	=	CO concentration in regenerator exhaust, percent by volume – dry basis. When no auxiliary fuel is burned and a continuous CO monitor is not required, assume %CO to be zero
%O ₂	=	O ₂ concentration in regenerator exhaust, percent by volume – dry basis

- (2) The person shall calculate process CO₂ emissions resulting from periodic catalyst regeneration using Equation 200-4.

$$E_{CO_2} = \sum_{i=1}^Y [CRC \times (CF_{spent} - CF_{regen})]_i \times 3.664$$

Equation 200-4

Where:

E_{CO_2}	=	CO ₂ emissions, tonnes /year
Y	=	Number of regeneration cycles
CRC	=	Mass of catalyst regenerated in the regeneration cycle, tonnes
CF _{spent}	=	Weight fraction of carbon in spent catalyst

CF_{regen} = Weight fraction of carbon in regenerated catalyst (default $CF_{\text{regen}} = 0$)

3.664 = Ratio of molecular weights, carbon dioxide to carbon

- (3) The person shall calculate process CO₂ emissions resulting from continuous catalyst regeneration in operations other than FCCUs and fluid cokers (e.g. catalytic reforming) using Equation 200-5.

$$E_{CO_2} = CRR \times (CF_{\text{spent}} - CF_{\text{regen}}) \times H \times 3.664$$

Equation 200-5

Where:

E_{CO_2} = CO₂ emissions, tonnes /year

CRR = Average catalyst regeneration rate, tonnes /hour

CF_{spent} = Weight fraction of carbon in spent catalyst

CF_{regen} = Weight fraction of carbon in regenerated catalyst (default $CF_{\text{regen}} = 0$)

H = Number of hours regenerator was operational in the year

3.664 = Ratio of molecular weights, carbon dioxide to carbon

- b) Process Vents. Except for process emissions reported under other requirements of this Guideline, the person shall calculate process emissions of CO₂, CH₄, and N₂O from process vents using Equation 200-6.

$$E_x = \sum_{i=1}^Y VR_i \times F_{x,i} \times \rho_x \times VT_i \times 0.001$$

Equation 200-6

Where:

E_x = Emissions of x (where x = CO₂, N₂O, or CH₄), tonnes /year

Y = Number of venting events

VR_i = Vent rate for venting event i, Sm³/unit time

$F_{x,i}$ = Molar fraction of x in vent gas stream during venting event i

ρ_x = Density of x, kg/ Sm³

VT_i = Time duration of venting event i (same unit of time used for VR_i)

0.001 = Conversion factor from kilograms to tonnes

- c) Asphalt Production. The person shall calculate CH₄ and CO₂ process emissions from asphalt blowing activities using Equations 200-7 and 200-8.

$$E_{CH_4} = (M_A \times EF \times \rho_{CH_4}) \times (1 - \frac{DE}{100}) \times 0.001 \quad \text{Equation 200-7}$$

Where:

E_{CH_4}	=	CH ₄ emissions, tonnes /year
M_A	=	Mass of asphalt blown, 103 bbl/year
EF	=	Emission factor (default EF = 72.35), Sm ³ CH ₄ /103 bbl
ρ_{CH_4}	=	Density of CH ₄ , kg/ Sm ³
DE	=	Control measure destruction efficiency, %
0.001	=	Conversion factor from kilograms to tonnes

$$E_{CO_2} = (M_A \times EF \times \rho_{CH_4}) \times \frac{DE}{100} \times 2.743 \times 0.001 \quad \text{Equation 200-8}$$

Where:

E_{CO_2}	=	CO ₂ emissions, tonnes /year
M_A	=	Mass of asphalt blown, 103 bbl/year
EF	=	Emission factor (default EF = 72.35), Sm ³ CH ₄ /103 bbl
ρ_{CH_4}	=	Density of CH ₄ , kg/Sm ³
DE	=	Control measure destruction efficiency, %
2.743	=	Ratio of molecular weights, carbon dioxide to methane
0.001	=	Conversion factor from kilograms to tonnes

- d) Sulfur Recovery. The person shall calculate CO₂ process emissions from sulfur recovery units (SRUs) using Equation 200-9. For the molecular fraction (MF) of CO₂ in the sour gas, use either a default factor of 0.20 or a source specific molecular fraction value derived from source tests. The person shall submit a pretest plan to the Director in the first year of reporting. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually

$$E_{CO_2} = FR \times MF \times \rho_{CO_2} \times 0.001 \quad \text{Equation 200-9}$$

Where:

E_{CO_2}	=	CO ₂ emissions, tonnes /year
FR	=	Volumetric flow rate of acid gas to SRU, Sm ³ /year
MF	=	Molecular fraction of CO ₂ in sour gas (default MF = 0.2)
ρ_{CO_2}	=	Density of CO ₂ , kg/Sm ³
0.001	=	Conversion factor from kilograms to tonnes

e) Flares and Other Control Devices.

(1) The person shall calculate and report CO₂, CH₄ and N₂O emissions resulting from the combustion of flare pilot and purge gas using the appropriate method(s) specified in sections ON.20.

(1) The person shall calculate and report CO₂ emissions resulting from the combustion of hydrocarbons routed to flares for destruction as follows:

(A) Use Equation 200-10 if the flare is equipped with a continuous flow and high heat value monitors:

$$E_{CO_2} = Flare \times HHV \times (EmF \times 0.001) \quad \text{Equation 200-10}$$

Where:

E_{CO_2}	=	CO ₂ emissions, tonnes /year
Flare	=	Volume of flare gas, Sm ³ /year
HHV	=	High heat value for refinery fuel or flare gas, GJ/Sm ³
EmF	=	CO ₂ emission factor (default EmF = 57.6), kg/GJ
0.001	=	Conversion factor from kilograms to tonnes

(B) Use Equation 200-11 if the flare is equipped with a continuous flow and carbon content monitors:

$$E_{CO_2} = Flare \times CC \times \rho \times 3.664 \times 0.001 \quad \text{Equation 200-11}$$

Where:

E_{CO_2}	=	CO ₂ emissions, tonnes /year
Flare	=	Volume of flare gas, Sm ³ /year
CC	=	Carbon content of flare gas, kg C/kg fuel
ρ	=	Density of flare gas, kg/Sm ³

- 3.664 = Ratio of molecular weights, carbon dioxide to carbon
0.001 = Conversion factor from kilograms to tonnes

(C) Use Equation 200-12 if the flare is not equipped with a continuous flow monitor and HHV or carbon content monitor:

$$E_{CO_2} = RFT \times EF_{NMHC} \times CF_{NMHC} \times 3.664 \times 0.001$$

Equation 200-12

Where:

- E_{CO_2} = CO₂ emissions, tonnes /year
RFT = Refinery feed input, Sm³/year
 EF_{NMHC} = Non-methane hydrocarbon emission factor (default EF_{NMHC} = 0.002), kg/ Sm³ throughput
 CF_{NMHC} = Conversion factor from non-methane hydrocarbon to carbon (default CF_{NMHC} = 0.6)
3.664 = Ratio of molecular weights, carbon dioxide to carbon
0.001 = Conversion factor from kilograms to tonnes

- (2) The person who uses methods other than flares (e.g. incineration, combustion as a supplemental fuel in heaters or boilers) to destroy low heat content gases (e.g. coker flue gas, gases from vapor recovery systems, casing vents and product storage tanks) shall calculate CO₂ emissions using Equation 200-13. The person shall determine CCA and MWA quarterly using methods specified in section ON.20 and use the annual average values of CCA and MWA to calculate CO₂ emissions.

$$E_{CO_2} = GV_i \times CC_i \times \rho_i \times 3.664 \times 0.001$$

Equation 200-13

Where:

- E_{CO_2} = CO₂ emissions from flare of gas i, tonnes /year
 GV_i = Volume of gas i destroyed annually, Sm³/year
 CC_i = Carbon content of gas i, kg C/kg fuel
 ρ_i = Density of gas i, kg/Sm³
3.664 = Ratio of molecular weights, carbon dioxide to carbon
0.001 = Conversion factor from kilograms to tonnes

- f) **Storage Tanks.** For above-ground storage tanks containing crude oil, asphalt, naphtha, and distillate oils that are not equipped with vapor recovery technology, the person shall calculate CH₄ emissions using the U.S. EPA TANKS Model. For crude oil, naphtha, and distillate oils, use the default chemical databases for crude oil (RVP 5), distillate fuel oil No. 2, and jet naphtha (JP4), respectively. For asphalt, use the data in Table 200-4 to create an asphalt chemical database. The annual throughput for each storage tank must be distributed equally across the twelve months of the year and the single-component liquid option selected. The total VOC emission values generated by the model shall be converted to methane emissions using:
- (1) A default conversion factor of 0.6 (CH₄ = 0.6 * VOC); or Species specific conversion factors determined by storage tank headspace vapor analysis using a sampling and analysis methodology. The person shall submit the sampling and analysis methodology to the Director in the first year of reporting. The analysis shall be repeated in each future year to update the species specific conversion factors annually.
- g) **Wastewater Treatment.**
- (1) The person shall calculate CH₄ emissions from wastewater treatment using Equation 200-14.

$$E_{CH_4} = [(Q \times COD_{qave}) - S] \times B \times MCF \times 0.001$$

Equation 200-14

Where:

E_{CH_4}	=	CH ₄ emissions, tonnes/year
Q	=	Volume of wastewater treated, m ³ /year
COD_{qave}	=	Average of quarterly determinations of chemical oxygen demand of the wastewater, kg/m ³
S	=	Organic component removed as sludge, kg COD/year
B	=	Methane generation capacity (default $B = 0.25$), kg CH ₄ /kg COD
MCF	=	Methane correction factor for anaerobic decay (0-1.0) from Table 200-2
0.001	=	Conversion factor from kilograms to tonnes

- (2) The person shall calculate N₂O emissions from wastewater treatment using Equation 200-15.

$$E_{N_2O} = Q \times N_{qave} \times EF_{N_2O} \times 1.571 \times 0.001$$

Equation 200-15

Where:

E_{N_2O}	=	N ₂ O emissions, tonnes/year
Q	=	Volume of wastewater treated, m ³ /year
N_{qave} N/m ³	=	Average of quarterly determinations of nitrogen in effluent, kg
EF_{N_2O}	=	Emission factor for N ₂ O from discharged wastewater (default $EF_{N_2O} = 0.005$), kg N ₂ O -N/kg N
1.571	=	Conversion factor from kg N ₂ O -N to kg N ₂ O
0.001	=	Conversion factor from kilograms to tonnes

- h) Oil-Water Separators. The person shall calculate CH₄ emissions from oil-water separators using Equation 200-16. For the CF_{NMHC} conversion factor, the person shall use either a default factor of 0.6 or species specific conversion factors determined by analysis using appropriate sampling and analysis methodology. The person shall submit the sampling and analysis methodology to the Director in the first year of reporting. The analysis shall be repeated in each future year to update the conversion factor annually.

$$E_{CH_4} = EF_{sep} \times V_{water} \times CF_{NMHC} \times 0.001$$

Equation 200-16

Where:

E_{CH_4}	=	CH ₄ emissions, tonnes/year
EF_{sep}	=	NMHC (non-methane hydrocarbon) emission factor from Table 200-3, kg/m ³ .
V_{water}	=	Volume of waste water treated by the separator, m ³ /year
CF_{NMHC}	=	Conversion factor from NMHC to CH ₄ (default $CF_{NMHC} = 0.6$)
0.001	=	Conversion factor from kilograms to tonnes

- i) Equipment leaks. The person shall calculate CH₄ emissions for all components in natural gas, refinery fuel gas, and PSA off-gas systems as follows:
- (1) Components shall be identified as one of the following classification types: valve, pump seal, connector, flange, open-ended line. The person shall use the method in CCME EPC-73: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993). The person shall conduct screenings at the frequency interval required by the Code of Practice.

(2) The volatile organic compounds (VOC) emissions shall be calculated using the following methods:

(A) For components where the measured screening value (SV) is indistinguishable from zero when corrected for background, the person shall calculate VOC emissions using Equation 200-17:

$$VOC_{0,i} = CC_i \times Zf_{i0} \times t_i \quad \text{Equation 200-17}$$

Where:

$VOC_{0,i}$	=	Zero component VOC emission for component type i, kg/screening period
i	=	Component type i (1 = valve, 2 = pump seal, 3 = other, 4 = connector, 5 = flange, 6 = open-ended line)
CC_i	=	Number of type i components where the screening value (SV) is 0
Zf_{i0}	=	Default zero factor for component type i from Table 200-5, kg/hour
t_i	=	Time lapse since last screening for component type i, hours

(B) For leaking components, the person shall calculate VOC emissions using the following methods:

$$VOC_{LC,i} = \sum_{y=1}^Y (\sigma_i \times SV_y^{\beta_i}) \times t_i \quad \text{Equation 200-18}$$

Where:

$VOC_{LC,i}$	=	VOC emissions for component type i with SV between 0 to 10,000 ppmv, kg/screening period
i	=	Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open ended-line)
Y	=	Number of type i components where the SV is between 0 to 10,000 ppmv
σ_i	=	Correlation equation coefficient for component type i from Table 200-5
SV_y	=	Screening value for component y
β_i	=	Correlation equation exponent for component type i from Table 200-5
t_i	=	Time duration for which the component has been leaking – default value is the time lapse since last screening, hours

$$VOC_{P,i} = CC_i \times PF_{iP-10} \times t_i \quad \text{Equation 200-19}$$

Where:

$VOC_{P,i}$	=	VOC emissions for component type i pegged over SV 9,999 ppmv, kg/screening period
i	=	Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open-ended line)
CC_i	=	Number of type i components pegged over 9,999 ppmv
PF_{iP-10}	=	VOC emission factor for component type i pegged over 9,999 ppmv from Table 200-5, kg/hour
t_i	=	Time duration for which the component has been leaking – default value is the time lapse since last screening, hours

- (C) The person shall calculate CH_4 emissions using Equation 200-20. The person shall use system specific determinations of gas composition and methane content (refinery fuel gas, natural gas, associated gas, flexigas, low heat content gas), where available, to determine a CFVOC value. The person shall submit the sampling and analysis methodology to the Director in the first year of reporting. The analysis shall be repeated in each future year to update the conversion factor annually. When representative data is not available, the person shall use the default value of 0.6 for CFVOC.

$$CH_{4,i} = \sum_{y=1}^Y (VOC_{0,i} + VOC_{LC,i} + VOC_{P,i}) \times CF_{VOC} \times 0.001 \quad \text{Equation 200-20}$$

Where:

$CH_{4,i}$	=	CH_4 emissions for component type i, tonnes/year
i	=	Component type (1 = valve, 2 = pump seal, 3 = others, 4 = connector, 5 = flange, 6 = open-ended line)
Y	=	Number of screenings per year for component type i
$VOC_{0,i}$	=	Zero component VOC emissions for component type i, kg/screening period
$VOC_{LC,i}$	=	VOC emissions for component i with SV between 0 to 10,000 ppmv, kg/screening period
$VOC_{P,i}$	=	VOC emissions for component type i pegged over 9,999 ppmv, kg/screening period
CF_{VOC}	=	Conversion factor from volatile organic compounds to methane (default CFVOC=0.6)

0.001 = Conversion factor from kilograms to tonnes

ON.204 Sampling, Analysis, and Measurement Requirements

- a) Catalyst Regeneration
 - (1) For FCCUs and fluid coking units, the person shall measure the following parameters:
 - (A) The daily oxygen concentration in the oxygen enriched air stream inlet to the regenerator.
 - (B) Continuous measurements of the volumetric flow rate of air and oxygen enriched air entering the regenerator.
 - (C) Continuous or weekly periodic measurements of the CO₂, CO and O₂ concentrations in the regenerator exhaust gas, to be determined by individual jurisdictions.
 - (D) Daily determinations of the carbon content of the coke burned
 - (E) The number of days of operation.
 - (2) For periodic catalyst regeneration, the person shall measure the following parameters.
 - (A) The mass of catalyst regenerated in each regeneration cycle.
 - (B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
 - (3) For continuous catalyst regeneration in operations other than FCCUs and fluid cokers, the person shall measure the following parameters.
 - (A) The hourly catalyst regeneration rate.
 - (B) The weight fraction of carbon on the catalyst prior to and after catalyst regeneration.
 - (C) The number of hours of operation.
- b) Process vents. The person shall measure the following parameters for each process vent.
 - (1) The vent flow rate for each venting event.
 - (2) The molar fraction of CO₂, N₂O, and CH₄ in the vent gas stream during each venting event.
 - (3) The duration of each venting event.
- c) Asphalt Production. The person shall measure the mass of asphalt blown.
- d) Sulfur Recovery. The person shall measure the volumetric flow rate of acid gas to the SRU. If using source specific molecular fraction value instead of the default factor, the person shall conduct an annual test of the CO₂ content using appropriate methods. The person shall submit a pretest plan to the Director in the first year of reporting. The source test procedures in that plan shall be repeated in each future year to update the source specific emission factors annually.

- e) Flares and Other Control Devices. The person shall measure the following:
 - (1) If using the method specified in ON.203(e)(1)(a), monitor the flow rate and high heat value of the flare gas using continuous monitors.
 - (2) If using the method specified in ON.203(e)(1)(b), monitor the flow rate and carbon content of the flare gas using continuous monitors.
 - (3) If using the method specified in ON.203(e)(2), monitor the volume of gas destroyed annually (determined to accuracy of $\pm 7.5\%$) and the carbon content.
- f) Storage Tanks. The person shall measure the annual throughput of crude oil, naphtha, distillate oil, asphalt, and gas oil for each storage tank using flow metres.
- g) Wastewater Treatment. The person shall measure the following parameters.
 - (1) The daily volume of waste water treated.
 - (2) The quarterly chemical oxygen demand of the wastewater.
 - (3) The amount of sludge removed and the organic content of the sludge.
 - (4) The quarterly nitrogen content of the wastewater.
- h) Oil-Water Separators. The person shall measure the daily volume of waste water treated by the oil-water separators using methods that comply with the measurement accuracy provisions in ON.2(d).
- i) Equipment Leaks. The person shall measure screening values for each valve, pump seal, connector, flange, and open-ended line used in natural gas, refinery fuel gas, and PSA off-gas systems using the methods specified in CCME EPC-73E: Environmental Code of Practice for the Measurement and Control of Fugitive VOC Emissions from Equipment Leaks (1993). The person shall conduct screenings at the frequency interval required by the Code of Practice.

Table 200-1. Coke burn rate material balance and conversion factors

	(kg : min)/(hour : DSm ³ : %)
K ₁	0.2982
K ₂	2.0880
K ₃	0.0994

Table 200-2. Default MCF Values for Industrial Wastewater

Type of Treatment and Discharge Pathway or System	Comments	MCF	Range
Untreated			
Sea, river and lake discharge	Rivers with high organic loading may turn anaerobic, however this	0.1	0 - 0.2

	is not considered here		
Treated			
Aerobic treatment plant	Well maintained, some CH ₄ may be emitted from settling basins	0	0 – 0.1
Aerobic treatment plant	Not well maintained, overloaded	0.3	0.2 – 0.4
Anaerobic digester for sludge	CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic reactor	CH ₄ recovery not considered here	0.8	0.8 – 1.0
Anaerobic shallow lagoon	Depth less than 2 metres	0.2	0 – 0.3
Anaerobic deep lagoon	Depth more than 2 metres	0.8	0.8 – 1.0
For CH ₄ generation capacity (B) in kg CH ₄ /kg COD, use default factor of 0.25 kg CH ₄ /kg COD. The emission factor for N ₂ O from discharged wastewater (EF _{N2O}) is 0.005 kg N ₂ O-N/kg-N. MCF = methane conversion factor (the fraction of waste treated anaerobically). COD = chemical oxygen demand (kg COD/m ³).			

Table 200-3. Emission Factors for Oil/Water Separators

Separator Type	Emission factor (EF _{sep}) ^a kg NMHC/m ³ wastewater treated
Gravity type - uncovered	1.11 x 10 ⁻¹
Gravity type - covered	3.30 x 10 ⁻³
Gravity type – covered and connected to destruction device	0
DAF ^b or IAF ^c - uncovered	4.00 x 10 ^{-3d}
DAF or IAF - covered	1.20 x 10 ^{-4d}
DAF or Iaf – covered and connected to a destruction device	0
^a EFs do not include ethane ^b DAF = dissolved air flotation type ^c IAF = induced air flotation device ^d EFs for these types of separators apply where they are installed as secondary treatment systems	

Table 200-4. Data for Preparing the Asphalt Chemical Database

Parametre	Database Entry
Liquid Molecular Weight	1000
Vapor Molecular Weight	105
Liquid Density (kg/m ³ at 15 °C)	969.7
Liquid Density (lb/gal. at 60 °F)	8.0925
Antoine's Equation Constants (using K)	A = 75350.06
	B = 9.00346

Table 200-5. Fugitive Emissions from Gas Service Components

Component Type / Service Type	Default Zero Factor (kg/hour) (SV = 0) Zf _{i0}	Correlation Equation (kg/hour) (SV > 0 and < 10,000) σ _i and β _i	Pegged Factor (kg/hour) (SV > 9,999) PF _{iP-10}
1, Valves	7.8 x 10 ⁻⁶	2.27 x 10 ⁻⁶ (SV) ^{0.747}	0.064
2, Pump seals	1.9 x 10 ⁻⁵	5.07 x 10 ⁻⁵ (SV) ^{0.622}	0.089
3, Others ^a	4.0 x 10 ⁻⁶	8.69 x 10 ⁻⁶ (SV) ^{0.642}	0.082
4, Connectors	7.5 x 10 ⁻⁶	1.53 x 10 ⁻⁶ (SV) ^{0.736}	0.030
5, Flanges	3.1 x 10 ⁻⁷	4.53 x 10 ⁻⁶ (SV) ^{0.706}	0.095
6, Open-ended lines	2.0 x 10 ⁻⁶	1.90 x 10 ⁻⁶ (SV) ^{0.724}	0.033

- ^a The “other” component type should be applied to any component type other than connectors, flanges, open-ended lines, pump seals, or valves. The “other” component type includes: instruments, loading arms, pressure relief valves, vents, compressors, dump lever arms, diaphragms, drains, hatches, metres, and polished rods stuffing boxes.

Appendix 21 Phosphoric Acid Production

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart Z, sections 98.260, 98.263 – 98.266.

Appendix 22 ON.210 Pulp and Paper Manufacturing

ON.211 Source Category Definition

The pulp and paper manufacturing source category consists of facilities that produce pulp either at stand-alone pulp facilities or integrated pulp and paper mills.

ON.212 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for pulp and paper manufacturing shall include the following information at the facility level calculated in accordance this method:

- Annual biogenic CO₂ process emissions from all recovery furnaces and kilns expressed in tonnes, as specified in ON.213.
- Annual CO₂ process emissions from make-up carbonate from all recovery furnaces and kilns expressed in tonnes, as specified in ON.213
- CO₂, N₂O, and CH₄ emissions from stationary combustion units not covered by this method shall follow the calculation methods and reporting requirements in ON.20.
- Annual consumption of carbonate expressed in tonnes.
- Annual black liquor production expressed in tonnes.

ON.213 Calculation of GHG Emissions

- Calculate biogenic CO₂ process emissions from recovery furnaces and kilns using Equation 210-1

$$E_{CO_2, biogenic} = \sum_{i=1}^{12} (BL_i \times CC_i \times 3.664) \quad \text{Equation 210-1}$$

Where:

$E_{CO_2, biogenic}$	=	Biogenic CO ₂ process emissions from recovery furnaces and kilns, tonnes/year
BL_i	=	Black liquor produced in month I, tonnes/month
CC_i	=	Carbon content of the black liquor (weight fraction)..
3.664	=	Ratio of molecular weight, carbon dioxide to carbon.

- Calculate CO₂ process emissions from make-up carbonates used in the recovery furnace and kiln system using Equation 210-2:

$$E_{CO_2,mc} = \sum_{i=1}^{12} \sum_{j=1}^n RM_{ij} \times EF_{ij}$$

Equation 210-2

Where:

- $ECO_{2,mc}$ = CO₂ process emissions from make-up carbonate from recovery furnace and kiln systems, tonnes/year
- RM_{ij} = Amount of make-up carbonate j consumed in month i, tonnes/month
- EF_{ij} = CO₂ emission factor based on make-up carbonate j in month I, determined using Table 1
- n = Number of carbonate materials

ON.214 Sampling, Analysis, and Measurement Requirements

- Measure the quantity of black liquor produced each month.
- Collect one sample per year of black liquor and analyze it for carbon content using ASTM D5373-08.
- For the amount of carbonate material consumed, either use records provided by the material supplier or monitor carbonate material consumption using the same plant instruments used for accounting purposes, such as weigh hoppers or belt weigh feeders.
- For the carbonate content of each carbonate material consumed, either use carbonate content data provided by the supplier, the appropriate default factor from Table 1, or collect monthly samples of each carbonate material consumed and analyze each sample for carbonate content using ASTM Methods C25-06, C1301-95 or C1271-99.

Table 1: Formulae, Formula Weights, and Carbon Dioxide Emission Factors for Common Carbonate Species

Carbonate	Mineral Name	Molecular Formula Weight	Emission Factor (tonnes CO ₂ /tonne Carbonate)
CaCO ₃	Calcite	100.1	0.4397
CaMg(CO ₃) ₂	Dolomite	184.4	0.4773
Na ₂ CO ₃	Soda ash (sodium carbonate)	106.0	0.4149

Appendix 23 ON.30 Refinery Fuel Gas Use within a Petroleum Refinery

ON.31 Source Category Definition

This source category consists of any combustion device that is located at a petroleum refinery and that combusts refinery fuel gas, still gas, flexigas, or associated gas.

ON.32 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for refinery fuel gas use within a petroleum refinery shall include the following information at the facility level calculated in accordance this method:

- a) Annual CO₂, CH₄, and N₂O emissions from refinery fuel gas combustion expressed in tonnes.
- b) Annual fuel consumption of each fuel in units of standard cubic metres.

ON.33 Calculation of GHG Emissions

- a) Calculation of CO₂ Emissions. The person shall calculate daily CO₂ emissions for each fuel gas system using any of the methods specified in paragraphs (a)(1) through (a)(5) of this section. Calculate the total annual CO₂ emissions from combustion of all fuel gas by summing the CO₂ emissions from each fuel gas system.
 - (1) Use a CEMS that complies with the provisions in Report EPS 1/PG/7.
 - (2) Calculate CO₂ emissions from each refinery fuel gas system and flexigas system using Equation 30-1 and measured carbon content and density of the gas calculated as required by Equation 30-1

$$E_{CO_2} = \sum_{i=1}^Y Fuel_i \times CC_i \times \rho_i \times 3.664 \times 0.001$$

Equation 30-1

Where:

E_{CO_2}	=	CO ₂ emissions, tonnes/year
Y	=	Number of operating days in a year
$Fuel_i$	=	Daily refinery fuel or flexigas combusted, Sm ³
CC_i	=	Daily average carbon content of the fuel, kg C/kg fuel
P_i	=	Daily average density of the refinery fuel or still gas, kg/Sm ³
3.664	=	Ratio of molecular weights, carbon dioxide to carbon
0.001	=	Conversion factor from kilograms to tonnes

- (A) For refinery fuel gas, the daily average carbon content shall be determined a minimum of 3 times a day (once every 8 hours) using on-line instrumentation or discrete laboratory analysis using the methods specified in ON.34.
- (B) For flexigas, the daily average carbon content shall be determined once per day using the methods specified in ON.34.
- (3) Calculate CO₂ emissions from each fuel gas system and flexigas system using Equation 30-2 and a daily average high heat value that is monitored using a continuous on-line instrument.

$$E_{CO_2} = \sum_{i=1}^Y HHV_i \times Fuel_i \times EF_{CO_2,i} \quad \text{Equation 30-2}$$

Where:

- E_{CO_2} = CO₂ emissions resulting from the combustion of fuel gas from an individual fuel gas system, tonnes/year
- Y = Number of operating days per year
- HHV_i = Daily average high heat value of fuel gas, derived from a continuous analyzer and integrated over a 24-hour period, GJ/Sm³
- $Fuel_i$ = Daily fuel consumption from all fuel combustion units burning gas from the system, Sm³
- $EF_{CO_2,i}$ = Daily CO₂ emission factor for an individual fuel gas system, developed using Equation 30-3, tonnes CO₂/GJ

$$EF_{CO_2,i} = \frac{CC_i}{HHV_i} \times \rho_i \times 3.664 \times 0.001 \quad \text{Equation 30-3}$$

Where:

- $EF_{CO_2,i}$ = Daily CO₂ emission factor for an individual fuel gas system, tonnes CO₂/GJ
- CC_i = Daily average carbon content for a fuel gas system, collected according to paragraph (a)(3)(A) of this section, kg C/kg fuel
- HHV_i = Daily average high heat value for a fuel gas system, collected according to paragraph (a)(3)(A) of this section, GJ/Sm³
- P_i = Daily average density of the gas for an individual fuel gas system, kg/Sm³
- 3.664 = Ratio of molecular weights, carbon dioxide to carbon

0.001 = Conversion factor from kilograms to tonnes

- (A) For Equation 30-3, the carbon content shall be determined once per day by on-line instrumentation or by laboratory analysis of a representative sample using the methods specified in ON.34. The HHV shall be determined from either the same sample used to conduct the carbon analysis or from on-line instrumentation using the hourly average value that coincides with the same hour in which the carbon content was determined.
 - (B) For facilities that meet the definition of a small refiner in Section 2, the emissions measurements and calculations for Equation 30-2 and 30-3 may be conducted weekly.
- (4) For associated gas, low heat content gas, or other fossil fuels; follow the requirements for general stationary source combustion sources in ON.23(b) or (c), as appropriate for each fuel.
 - (5) Where individual fuels are mixed prior to combustion, the person may choose to calculate CO₂ emissions for each fuel prior to mixing instead of using the methods in paragraphs (a)(1), (a)(2), or (a)(3) of this section. In this case, the person must determine the fuel flow rate and appropriate fuel specific parameters (i.e., carbon content, HHV) of each fuel stream prior to mixing, calculate CO₂ emissions for each fuel stream, and sum the emissions of the individual fuel streams to determine total CO₂ emissions from the mixture. CO₂ emissions for each fuel stream must be estimated using the following methods:
 - (A) For natural gas and associated gas, use the appropriate methodology specified in section ON.23(b) or (c).
 - (B) For refinery fuel gas and flexigas, use the methodology in either paragraph (a)(2) or (a)(3) of this section.
 - (C) For low heat content gas, use the methodology in paragraph (a)(2) of this section.
 - b) Calculation of CH₄ and N₂O Emissions. The person shall use the methods specified in section ON.24 to calculate the annual CH₄ and N₂O emissions.

ON.34 Sampling, Analysis, and Measurement Requirements

- a) Measure the fuel consumption rate daily using methods specified in ON.25(b).
- b) Measure the carbon content for fuel gas and flexigas using either ASTM D1945-03 or ASTM D1946-90. Where these methods do not adequately quantify all major hydrocarbons, the person may request from the Director use of an alternative ASTM or other method. The person shall notify the Director of the use of the alternative methodology and submit the non-ASTM methodology to the Director in the first year of reporting.

- c) Measure high heat value using the monitoring requirements specified in ON.25(c) for gaseous fuels.

Appendix 24 Soda Ash Manufacturing

The person shall use the method set out in U.S. EPA, 40 CFR 98, Subpart CC, sections 98.290, 98.293 – 98.296.

Appendix 25 Steel Manufacturing

The person shall use the method set out in Appendix 14 - Iron and Steel Manufacturing.

Appendix 26 ON.240 Zinc Production

ON.241 Source Category Definition

The zinc production source category includes three primary production processes used to produce zinc, namely electro-thermic distillation, pyrometallurgical, and electrolytic. Secondary zinc production is also included in this category.

ON.242 Greenhouse Gas Reporting Requirements

For the purpose of S. 6 of the Regulation the annual emissions data report for zinc production shall include the following information at the facility level calculated in accordance this method:

- Annual emissions of CO₂, N₂O, CH₄ at the facility level expressed in tonnes
- Annual quantities of each reducing agent used expressed in tonnes
- Carbon content of each reducing agent used, tonne C/tonne reducing agent
- Annual CO₂, N₂O, and CH₄ emissions from stationary combustion units as specified in ON.20 expressed in tonnes/year.

ON.243 Calculation of CO₂ Emissions

Calculate total CO₂ emissions as specified under paragraph (a) or (b) of this section.

- Use a CEMS that complies with the provisions in Report EPS 1/PG/7.
- Determine facility CO₂ emissions using carbon contents and quantities of reducing agents.

$$E_{CO_2} = \sum_x (RA_x \times C_x) \times 3.664 \quad \text{Equation 243-1}$$

Where:

- | | | |
|------------------|---|--|
| ECO ₂ | = | Annual CO ₂ emissions from reducing agents, tonne/year; |
| RA _x | = | Annual quantity of reducing agent x, tonne/year; |
| C _x | = | Carbon content of reducing agent x, tonne C/tonne reducing agent; |
| 3.664 | = | Ratio of molecular weights of carbon dioxide to carbon. |

ON.244 Sampling, Analysis, and Measurement Requirements

- Carbon contents of reducing agents shall be determined as specified under paragraph (b) or (c) of this section as required in ON.243(b).
- Carbon contents from reducing agents should be determined in the following manner:

- (1) For coal and coke, use ASTM D5373-02.
 - (2) For petroleum-based liquid fuels and liquid waste-derived fuels, use ASTM D5291-02, ultimate analysis of oil or computations based on ASTM D3238-95 and either ASTM D2502-04 or ASTM D2503-92.
 - (3) For gaseous fuels, use ASTM D1945-03 or ASTM D1946-90.
- c) Carbon contents from reducing agents should be obtained from material vendor or supplier.

